

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to)
approve large load tariff, by Duke Energy) DOCKET NO. 20260064-EI
Florida, LLC.) DATED: August 18, 2026
_____)

**WHITE SPRING AGRICULTURAL CHEMICALS, INC. d/b/a PCS PHOSPHATE –
WHITE SPRINGS’ AND NUCOR STEEL FLORIDA, INC.’S NOTICE OF INTENT TO
SEEK AND MOTION FOR OFFICIAL RECOGNITION**

Pursuant to Rule 28-106.213(6), Florida Administrative Code (“F.A.C.”), Sections 90.201 through 90.203 and 120.569(2)(i), Florida Statutes, and the *Order Establishing Procedure*, Order No. PSC-2026-0120-PCO-EI, dated May 5, 2026, White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs and Nucor Steel Florida, Inc. (“Joint Movants”) hereby move for official recognition of the following documents, which are included hereto as Exhibits A through J:

- Exhibit A: Virginia State Corporation Commission, Case No. PUR-2025-00058, Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia, Final Order (Nov. 25, 2025)
- Exhibit B: Missouri Public Service Commission, Case No. EO-2025-0154, In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of New and Modified Tariffs for Service to Large Load Customers, Report and Order (Nov. 13, 2025)
- Exhibit C: HR9340 (Ratepayer Protection Act) – Transcript of House Energy & Commerce July 21, 2026 meeting and amendment in the nature of a substitute
- Exhibit D: Federal Energy Regulatory Commission, Docket No. RD26-7, Reliability Standard(s) Pertaining to Computational Load Integration, 196 FERC ¶ 61,031 (July 16, 2026) – Order Directing the North American Electric Reliability Corporation to File Reliability Standard(s) Pertaining to Computational Load Integration
- Exhibit E: Federal Energy Regulatory Commission, Docket No. ER26-247-000, Southwest Power Pool, Inc., 194 FERC ¶ 61,031 (Jan. 14, 2026) – Order Accepting Tariff Revisions, Subject to Condition

- Exhibit F: Federal Energy Regulatory Commission, Docket No. EL26-27-000, PJM Interconnection, L.L.C., et al., 195 FERC ¶ 61,211 (June 18, 2026) – Order Instituting Proceeding Under Section 206 of the Federal Power Act
- Exhibit G: Executive Office of the Governor Ron DeSantis, 46th Governor of Florida, Governor Ron DeSantis Signs Law to Protect Floridians from Subsidizing Data Centers (May 7, 2026)
- Exhibit H: Federal Energy Regulatory Commission, Docket No. ER26-3515-000, PJM Interconnection, L.L.C., Proposal of PJM Interconnection, L.L.C. to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability (Aug. 13, 2026)
- Exhibit I: North American Electric Reliability Corporation, Essential Action to Industry: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control (May 4, 2026)
- Exhibit J: North American Electric Reliability Corporation, Final Risk Mitigation for Emerging Large Loads: Large Loads Working Group Reliability Guideline (May 2026)

In support of the motion, Joint Movants state as follows:

1. A party to an administrative proceeding may move for official recognition of certain documents pursuant to the provisions governing judicial notice in Sections 90.201 through 90.203, Florida Statutes. *See* Rule 28-106.213(6), F.A.C.
2. Section IV, paragraph H of the Order Establishing Procedure takes official recognition of a variety of documents.
3. **Exhibits A and B:** Section 90.202(2), Florida Statutes permits judicial notice of “[d]ecisional . . . law of every other state, territory, and jurisdiction of the United States.” Orders issued by administrative agencies in other states are decisional law. Exhibit A is decisional law issued by the Virginia State Corporation Commission. Exhibit B is decisional law issued by the Missouri Public Service Commission. Exhibits A and B therefore meet the requirements of section 90.202(2), Florida Statutes. Exhibits A and B are relevant because they address issues related to serving large loads.

4. Section 90.202(5), Florida Statutes permits judicial notice of “[o]fficial acts of the legislative, executive, and judicial departments of the United States or of any state, territory, or jurisdiction of the United States.” The following exhibits meet the requirements of Section 90.202(5):

Exhibit C: A hearing held by a committee of the United States House of Representatives is an official action of the United States Congress. Exhibit C is a transcript of a hearing held by the House Energy and Commerce Committee, along with an amendment in the nature of a substitute adopted by the Committee. Exhibit C therefore meets the requirements of section 90.202(5), Florida Statutes. Exhibit C is relevant because it addresses positions of federal legislators with respect to certain large loads.

Exhibits D through F: Orders issued by the Federal Energy Regulatory Commission (“FERC”) are official acts of an executive department of the United States. Exhibit D is an order issued by FERC directing the North American Electric Reliability Corporation (“NERC”) to file reliability standards pertaining to computational load integration. Exhibit E is an order issued by FERC accepting tariff revisions for Southwest Power Pool, Inc. Exhibit F is an order issued by FERC directing PJM, Interconnection, L.L.C. to show cause as to why its tariff is just and reasonable and not unduly discriminatory with respect to large loads. Exhibits D, E, and F therefore meet the requirements of section 90.202(5). Exhibits D, E, and F are relevant because they address positions taken by FERC with respect to large loads.

5. **Exhibits G through J:** Section 90.202(11), Florida Statutes, permits judicial notice of “[f]acts that are not subject to dispute because they are generally known within the territorial jurisdiction of the court.” Section 90.202(12), Florida Statutes, permits judicial notice of “[f]acts

that are not subject to dispute because they are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned.” Exhibit G is a press release from Governor Ron DeSantis’ office, dated May 7, 2026, and it provides Governor DeSantis’ understanding of SB484. Exhibit H is a proposal submitted by PJM Interconnection, L.L.C. to FERC that addresses issues related to serving large loads. Exhibit I is an alert issued by NERC to address risks associated with certain large loads. Exhibit J is a report issued by NERC that provides recommendations to mitigate risks associated with large loads. The foregoing materials are generally known within the State of Florida, and/or are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned. They are relevant because they demonstrate the positions and/or actions of the Florida Governor’s Office, FERC, PJM Interconnection, L.L.C. (the largest grid operator in the United States), and NERC regarding the risks posed by large loads.

6. Pursuant to section 90.202(2), 90-202(3), 90-202(5), and 90-202(11)-(12), Joint Movants respectfully request official recognition of Exhibits A through J attached hereto.

7. Pursuant to the notice requirements in section IV, paragraph H of the Order Establishing Procedure, section 120.569(2)(i), Florida Statutes, and Rule 28-106.213(6), F.A.C, Joint Movants hereby provide notice to the parties of record of Joint Movants’ intent to seek official recognition. Additionally, pursuant to Rule 28-106.204(3), Joint Movants have conferred with the other parties of record and are authorized to represent that the Florida Industrial Power Users Group (“FIPUG”) supports the motion and that Duke Energy Florida, the Office of Public Counsel, and Florida Rising, Inc. take no position.

WHEREFORE, Joint Movants respectfully requests that the Commission take official recognition of the following documents, attached hereto as Exhibits A through J:

- Exhibit A: Virginia State Corporation Commission, Case No. PUR-2025-00058, Application of Virginia Electric and Power Company for a 2025 biennial review of the

rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia, Final Order (Nov. 25, 2025)

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Respectfully submitted,

/s/ James W. Brew

James W. Brew
Laura Wynn Baker
Sarah B. Newman
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St, NW
Suite E-3400
Washington, D.C. 20007
(202) 342-0800 (phone)
(202) 342-0807 (fax)
jbrew@smxblaw.com
lwb@smxblaw.com
sbn@smxblaw.com

*Attorneys for White Springs Agricultural
Chemicals, Inc. d/b/a PCS Phosphate –
White Springs*

/s/ Michael K. Lavanga

Peter J. Mattheis
Michael K. Lavanga
Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St, NW
Suite E-3400
Washington, D.C. 20007
(202) 342-0800 (phone)
(202) 342-0807 (fax)
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

Attorneys for Nucor Steel Florida, Inc.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing has been furnished by electronic mail and/or U.S. Mail this 18th day of August 2026 to the following:

Office of Public Counsel

Walt Trierweiler
Charles J. Rehwinkel
Octavio Simoes-Ponce
Austin A. Watrous
c/o The Florida Legislature
111 West Madison Street
Suite 812
Tallahassee, FL 32399-1400
trierweiler.walt@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
ponce.octavio@leg.state.fl.us
watrous.austin@leg.state.fl.us

Florida Public Service Commission Office of General Counsel

Major Thompson
Saad Farooqi
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
major.thompson@psc.state.fl.us
sfarooqi@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Florida Rising, Inc.

Bradley Mashall
Jordan Luebkekmann
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, FL 32301
bmarshall@earthjustice.org
jluebkekmann@earthjustice.org
flcaseupdates@earthjustice.org

Duke Energy Florida, LLC

Matthew R. Bernier/Stephanie Cuello
106 E. College Avenue, Ste. 800
Tallahassee, FL 32301
Matt.Bernier@duke-energy.com
Stephanie.Cuello@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Dianne M. Triplett
299 1st Avenue North
St. Petersburg, FL 33701
Dianne.Triplett@duke-energy.com

Florida Industrial Power Users Group

Jon C. Moyle, Jr.
Karen A. Putnal
c/o Moyle Law Firm
118 North Gadsden Street
Tallahassee FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

/s/ Joseph R. Briscar

EXHIBIT A

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

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State Corporation Commission
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AT RICHMOND, NOVEMBER 25, 2025

APPLICATION OF

VIRGINIA ELECTRIC AND POWER COMPANY

CASE NO. PUR-2025-00058

For a 2025 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia

FINAL ORDER

This proceeding is a biennial review of Virginia Electric and Power Company's ("Dominion" or "Company") rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia ("Code"). This case will set Dominion's base rates for the next two calendar years (*i.e.*, January 1, 2026, through December 31, 2027). In its Application, the Company requested a revenue increase of \$822 million for 2026, and a further incremental revenue increase of \$345 million for 2027. Dominion also proposed certain changes to its rate schedules and its terms and conditions of service.

In parallel with this proceeding, Dominion filed an application to revise its fuel factor pursuant to Code § 56-249.6.¹ While the details of that matter will be addressed more fully in the final order in Case No. PUR-2025-00059, the issue of capacity costs straddles both cases, as the Company proposes to shift these costs from base rates to the fuel factor.

¹ *Application of Virginia Electric and Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6, Case No. PUR-2025-00059, Doc. Con. Cen. No. 250520127, Application (filed Mar. 31, 2025).*

As proposed by the Company across the two applications—exclusive of fuel costs but inclusive of capacity costs—a typical residential customer² would experience a monthly bill increase of \$14.73, or 9.8%, in 2026 and an additional \$4.84, or 2.9%, in 2027.³

Pursuant to the Commission’s Order for Notice and Hearing: (1) Dominion provided public notice of its Application; (2) the Commission received public comments on the Application; and (3) the Commission convened a nine-day evidentiary hearing from September 2-12, 2025, which included testimony from public witnesses and participation by Dominion, Commission Staff (“Staff”), and certain parties filing as respondents herein.⁴

Post-hearing briefs were filed by Dominion, Staff, and the following respondents: Office of the Attorney General’s Division of Consumer Counsel (“Consumer Counsel”); Amazon Data Services, Inc.; Apartment and Office Building Association of Metropolitan Washington (“AOBA”); Appalachian Voices (“APV”); Clean Virginia; CloudHQ LLC; Data Center Coalition (“DCC”); Google, LLC (“Google”); Iron Mountain Data Centers, LLC; Microsoft Corporation; Piedmont Environmental Council; Retail Energy Advancement League; Sierra Club; U.S. Department of Defense and all other Federal Executive Agencies; Virginia Committee for Fair Utility Rates (“Committee”); and Walmart Inc. (“Walmart”).

² For these purposes, the typical residential customer is defined as one using 1,000 kilowatt-hours (“kWh”) per month.

³ *See, e.g.*, Dominion’s April 11, 2025, letter clarifying certain requests in the Application. The percentage change is calculated in comparison to the residential bill as of July 1, 2025, which was \$149.92. Ex. 6 (Dominion Response to QAG Interrogatory No. 12-237).

⁴ Pursuant to Commission order, the evidentiary hearing was combined with the evidentiary hearing for the Company’s fuel factor application in Case No. PUR-2025-00059.

NOW THE COMMISSION, upon consideration of this matter, is of the opinion and finds as follows.⁵

There was considerable concern among the public, demonstrated through both written comments and public witness testimony, regarding the potential for an increase in rates, especially within the residential rate class. Two aspects in particular were often repeated: (1) that the motivating factors underlying the Company's request for a rate increase that would impact residential customers was designed primarily to subsidize data centers; and (2) that, given the price increases in food, shelter, and consumer goods generally over the last few years, any rate increase at this juncture should be disallowed.

Other portions of this order will address the specifics associated with large-load customers, including data centers. The Commission endeavors at every opportunity to allocate costs appropriately across all customer classes to ensure a reasonable result. The same holds true in this case.

The concern associated with rate increases generally, and at this juncture in particular, is understandable. However, many of the same inflationary, economic, and policy impacts that have affected other segments of the economy providing goods and services to consumers apply as well to companies providing electric service. The Company is not immune from current and projected increases in costs associated with raw materials and labor. As the utility regulator, we are obligated by law to set a revenue requirement that affords the Company an opportunity to

⁵ The Commission has fully considered the record, including the post-hearing briefs filed in this matter. The Commission directed that each post-hearing brief include a list of issues for which the participant requests a ruling. Tr. 2672. To the extent this Final Order does not speak to a particular issue or claim, the Commission has found (as supported by the record) that such is neither legally nor factually necessary and that the provisions approved herein are reasonable.

recover reasonable and prudent projected costs and earn a reasonable rate of return. In this case, that has resulted in an increase in rates, but not to the extent requested by Dominion.

2023-2024 EARNINGS REVIEW

The Commission is required to review the Company's 2023-2024 earnings in this biennial review. Based on the record in this proceeding, it is uncontested that Dominion's earned return for 2023-2024 was less than its authorized return on equity ("ROE") of 9.7% over that same period.⁶

2026-2027 BASE RATES

The Commission is required to revise Dominion's prospective base rates as necessary "to ensure the resulting base rates (a) are just and reasonable and (b) provide the utility an opportunity to recover its costs of providing services over the rate period . . . and earn a fair rate of return on its base rates[.]"⁷

The Commission finds an annual base rate revenue increase of \$565.7 million for 2026, followed by an annual base rate revenue increase of \$209.9 million for 2027, to be just and reasonable, and sufficient to provide Dominion an opportunity to recover its costs of providing services and earn a fair rate of return on its base rates.⁸ These base rate adjustments result in approximate monthly bill increases for a typical residential customer of \$11.24, or 7.5%, in 2026 and an additional \$2.36, or 1.5%, in 2027. This represents a decrease of \$3.49, or 23.7%, in

⁶ See, e.g., Ex. 89 (Myers Direct) at 14-15; Ex. 105 (McLeod Rebuttal) at 2.

⁷ Code § 56-581 C.

⁸ The rates approved herein shall take effect for service rendered on and after January 1, 2026, and January 1, 2027. A reconciliation from Dominion's requested revenue requirement, as set forth in its rebuttal testimony, to the revenue requirement approved herein is included as an Attachment to this Final Order.

2026 and \$2.48, or 51.2%, in 2027 from the Company's proposals as described above. In reaching this conclusion, the Commission made specific findings as discussed below.

RETURN ON EQUITY

The table below provides a summary of the ROE witness testimony presented in this proceeding.⁹

	<u>ROE Range</u>	<u>Recommended ROE</u>
Dominion	10.30% - 11.60%	10.40% ¹⁰
Clean Virginia	n/a	6.01% ¹¹
Committee	9.25% - 9.70%	9.50% ¹²
Consumer Counsel	8.75% - 9.75%	9.25%/9.50% ¹³
DCC	7.50% - 8.90%	8.90% ¹⁴
Staff	9.30% - 10.30%	9.80% ¹⁵

⁹ Respondents not included in the table did not present witness-sponsored testimony regarding the appropriate ROE for Dominion in this proceeding. The Commission notes, however, that while Google did not have a specific ROE recommendation, it recommended the Commission establish an ROE that reflects risk adjustment commensurate with specific High Load Proposals. Ex. 53 (Berry Direct) at 4, 55-56. Further, while AOBA did not make a specific ROE recommendation in pre-filed testimony, they stated that the Company's proposed capital structure and rates of return increase the Company's perceived revenue requirement and shift financial risk onto customers. Ex. 7 (Oliver Direct) at 4.

¹⁰ Ex. 14 (Nelson Direct) at 4.

¹¹ Ex. 61 (M. Ellis Direct) at 5-6. This ROE was based, at least in part, on a discounted cash flow result of 6.74% and a capital asset pricing model result of 5.45%, though no formal cost of equity range was provided in testimony. This ROE was recommended in conjunction with a 57.8% equity ratio. *Id.*

¹² Ex. 56 (Gorman Direct) at 5.

¹³ Ex. 69 (Woolridge Direct) at 4-5. Consumer Counsel's recommendation is dependent on the equity ratio used in the weighted average cost of capital. Consumer Counsel recommends a 9.25% ROE with a 52.1% equity ratio or a 9.5% ROE with a 50% equity ratio.

¹⁴ Ex. 38 (Garrett Direct) at 4-5. This ROE was recommended in conjunction with a 42.38% equity ratio. *Id.* at 7.

¹⁵ Ex. 80 (Gereaux Direct) at 2.

VPLC	n/a	≤9.70% ¹⁶
Walmart	n/a	≤9.70% ¹⁷

Based on the record in this proceeding and applicable law and precedent, the Commission finds that a cost of equity within a range of 9.3% to 10.3% fairly represents the actual cost of equity in capital markets for companies comparable in risk to Dominion seeking to attract equity capital. The Commission further concludes that, within that range, a specific ROE of 9.8% is fair and reasonable, supported by evidence in the record, and satisfies the standards set forth in *Hope* and *Bluefield*.¹⁸

In setting Dominion's fair ROE, the Commission is permitted to use "any methodology to determine such return it finds consistent with the public interest[.]"¹⁹ The Commission has previously recognized that "[t]here is no single scientific correct rate of return"²⁰ The Commission, however, is guided by the standards set forth in the United States Supreme Court's *Hope* and *Bluefield* decisions, which do not establish a particular method for determining an allowed ROE but, rather, require that the end result be sufficient to allow the utility to attract new capital on reasonable terms, maintain its financial integrity, and offer a return commensurate

¹⁶ Ex. 59 (Wiggins Direct) at 7-8. While the Virginia Poverty Law Center ("VPLC") did not conduct an ROE analysis, they opposed an increase in the Company's ROE.

¹⁷ Ex. 68 (Chriss Direct) at 5.

¹⁸ *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

¹⁹ Code § 56-585.1 A 2 a.

²⁰ *Commonwealth ex rel. Div. of Consumer Counsel v. Potomac Edison Co.*, 233 Va. 165, 171 (1987) (quoting *Central Tel. Co. of Va. v. State Corp. Comm'n*, 219 Va. 863, 874 (1979)).

with other investments of comparable risks.²¹ The Commission finds that the result herein satisfies these standards.²²

CAPITAL STRUCTURE AND COST OF CAPITAL

The Commission approves Staff's recommended capital structure (which includes an equity ratio of 52.035%) and cost of debt, along with the ROE approved above, for rate setting purposes for the 2026 and 2027 rate years and applicable rate adjustment clauses.²³ We find that this reflects Dominion's "actual end-of-test period capital structure and cost of capital," and we do not find that the "debt to equity ratio of such capital structure is unreasonable."²⁴

PURCHASED CAPACITY EXPENSE

The Commission finds that it is reasonable at this time not to shift cost recovery of purchased capacity expenses from base rates to the fuel factor.²⁵ While this decision will alter the timing of the recovery of these costs vis à vis the Company's Application, it will not have an impact on the overall amount of these costs.

²¹ See, e.g., *Hope* at 602, 603 (finding, among other things, that "the [Federal Power Commission] was not bound to the use of any single formula or combination of formulae in determining rates" as the "rate-making function . . . involves the making of 'pragmatic adjustments.'").

²² This finding is supported by, among other things, the testimony in this proceeding from Staff witness Gereaux.

²³ See, e.g., Ex. 78 (Hunt Supp.) at 2-3. See also Code § 56-585.1 A 8 e.

²⁴ Code § 56-585.1 A 11.

²⁵ See, e.g., Ex. 29 (Gaskill Direct) at 10-14; Ex. 71 (R. Smith Direct) at 14-15; Ex. 53 (Berry Direct) at 48-50; Ex. 89 (Myers Direct) at 15-26; Ex. 92 (Myers Illustration of Capacity); Ex. 111 (Gaskill Rebuttal) at 21-25; Tr. 990-992 (Abbott), 1711-1715 (Myers).

SERVICE COMPANY BILLING PERCENTAGE

The Commission approves Dominion's service company billing percentage for Dominion Energy Services, Inc.²⁶ In addition, the Commission finds that, consistent with the current two-year biennial review cycle, the Company shall complete a lower of cost or market study every two years.²⁷

DSM-EE AND VO SALES REDUCTIONS

Dominion has not established the reasonableness of its forecasted sales reductions from demand-side management and energy efficiency ("DSM-EE") and voltage optimization ("VO") programs. Rather, based upon consideration of prior and current forecasts, the Commission finds that 66.7% of the current forecast is reasonably predicted to occur during the rate years.²⁸

We note with concern the Company's declining trend with respect to these programs.²⁹ While we elect to apply the prior year's percentage of that year's forecast in this case, holding the Company's expected performance steady, a simple regression analysis from 2022 through 2024 would suggest that a lower percentage would be expected. This trend was earlier observed in Case No. PUR-2023-00227, which noted that the Company was unsuccessful in meeting the thresholds set forth in Code § 56-596.2 B 2 b and c. If load growth unfolds as projected, it will become even more important for the Company to reverse the current trend and seek to meet the targets set forth in Case No. PUR-2023-00227.

²⁶ See, e.g., Ex. 71 (R. Smith Direct) at 31-34; Ex. 89 (Myers Direct) at 60-68; Ex. 105 (McLeod Rebuttal) at 13-15; Ex. 117 (Wenger Rebuttal) at 2-7.

²⁷ Tr. 1760-1761 (Myers).

²⁸ See, e.g., Ex. 107 (DSM/EE/VO Attainment); Tr. 2491-2498 (Frost); Dominion's Post-Hearing Brief at 9; Ex. 81 (S. Smith Direct) at 4-8.

²⁹ Ex. 107 (DSM/EE/VO Attainment); Tr. 2497-2498 (Frost); Staff's Post-Hearing Brief at 20-21.

OFFSHORE WIND INVESTMENT TAX CREDITS

The investment tax credits related to the Coastal Virginia Offshore Wind pilot project shall be amortized over the 2026-2027 two-year period.³⁰

DATA CENTER CAPITAL EXPENDITURES AND REVENUES

Dominion has not established that 100% of its forecasted data center expenditures are reasonably predicted to occur during the rate years. Rather, the Commission finds that the revenue requirement expenditures and revenues reflected in Ex. 86, Scenario 2 (Revenue Requirement Impacts of Incorporating Executed Electric Service Agreements (“ESA”) and Executed/Pending Construction Letters of Authorization), are reasonably predicted to occur.³¹

The size of individual large-load customers, their number, and the speed with which they are seeking to connect to the system, jointly present challenges for the Company, existing customers, and the grid at large not seen in decades, if ever. Scenario 2 presents a reasonable forecast of what is likely to occur over the course of the upcoming biennium. In 2027, all participants will have the benefit of two more years’ experience with these large-load customers, any initial impacts of the tariff design that we approve today, and potential technological innovations and other developments that could all impact the rate of growth of the projected load forecast.

Despite statements made during the hearing and on brief,³² a reduction in these forecasted expenditures from the Company’s proposal is not a disallowance. Should investments in this

³⁰ See, e.g., Ex. 71 (R. Smith Direct) at 39-41; Ex. 84 (Long Direct) at 32-33; Ex. 108 (Lee Rebuttal) at 24.

³¹ See, e.g., Ex. 70 (Norwood Direct) at 16-20; Ex. 84 (Long Direct) at 7-15; Ex. 89 (Myers Direct) at 37-45; Ex. 105 (McLeod Rebuttal) at 24; Ex. 114 (Blackwell Rebuttal) at 34-35; Ex. 120 (Locke Rebuttal) at 3-12; Ex. 134 (Baine Rebuttal) at 7; Tr. 1625-1636 (Long), 2466-2472 (Locke).

³² Tr. 2104, 2120 (McLeod); Dominion’s Post-Hearing Brief at (ii)-(iii).

area outpace those we have found reasonably likely to occur within the rate period, mechanisms exist to allow for their later recovery, presuming such costs are reasonable and prudently incurred. To the extent such mechanisms involve financing costs, the Commission has significant discretion regarding the period over which such costs ought to be recovered. Further, the establishment of the GS-5 rate class, below, will allow for a more accurate accounting of such costs.

Relatedly, the Commission directs the Company to implement the forecasting of large load, high load factor customer revenue and capital investments in its next biennial review as set forth in Ex. 93.

POWER DELIVERY O&M EXPENSES

The Commission approves the Power Delivery operations and maintenance (“O&M”) expenses forecasted by Dominion as reasonably predicted to occur during the rate years.³³

FOSSIL AND HYDRO PLANNED OUTAGE EXPENSES

Dominion has not established that 100% of its forecasted Fossil and Hydro Planned Outage expenses are reasonably predicted to occur during the rate years, and the Commission approves as reasonable Staff’s adjustments thereto.³⁴

DEFERRED FUEL BALANCE

The Commission approves Dominion’s correction that eliminates the inadvertent inclusion of the deferred fuel balance from rate base.³⁵

³³ See, e.g., Ex. 87 (Ottwell Direct) at 23-26; Ex. 108 (Lee Rebuttal) at 21-23; Ex. 120 (Locke Rebuttal) at 11.

³⁴ See, e.g., Ex. 83 (Clayton Direct) at 12-13; Ex. 108 (Lee Rebuttal) at 18-19.

³⁵ See, e.g., Ex. 108 (Lee Rebuttal) at 13; Tr. 1782-1783 (Myers), 2109-2113 (McLeod).

POWER GENERATION CAPITAL SPEND

Dominion has not established that 100% of its forecasted Power Generation Capital Spend is reasonably predicted to occur during the rate years, and the Commission approves as reasonable Staff's adjustments thereto.³⁶

NUCLEAR PRODUCTION TAX CREDIT

For purposes of calculating the Nuclear Production Tax Credit, the Commission incorporates the Company's proposed service company billing percentage, and the cost of capital approved herein. The Commission approves Staff's remaining adjustments related to the Nuclear Production Tax Credit.³⁷

GRID TRANSFORMATION PLAN BENEFITS

The Commission approves the O&M expense reductions proposed by the Company to incorporate projected savings associated with its Grid Transformation Plan during the rate years.³⁸

NON-RECURRING CUSTOMER ACCOUNTS EXPENSE

The Commission approves Staff's adjustments to non-recurring customer accounts O&M expenses associated with the Company's new billing system and the development and implementation of the new residential bill redesign.³⁹

³⁶ See, e.g., Ex. 84 (Long Direct) at 16, 22-23; Ex. 119 (Green Rebuttal) at 3-5; Tr. 1638-1640 (Long), 2457-2459 (Green).

³⁷ See, e.g., Ex. 84 (Long Direct) at 29-31; Ex. 105 (McLeod Rebuttal) at 25-26.

³⁸ See, e.g., Ex. 89 (Myers Direct) at 55-59; Ex. 108 (Lee Rebuttal) at 19-21; Tr. 1770-1779 (Myers), 2130-2133 (Lee).

³⁹ See, e.g., Ex. 83 (Clayton Direct) at 15-16; Ex. 105 (McLeod Rebuttal) at 26-27.

PURCHASED CAPACITY REGULATORY ASSET

As recommended by Consumer Counsel and Staff, the Commission finds that the future ratemaking treatment, including recovery of any financing costs, associated with Dominion's Purchased Capacity Regulatory Asset shall be adjudicated in the Company's next biennial review.⁴⁰

ADVANCED METERING INFRASTRUCTURE AND CUSTOMER INFORMATION PLATFORM

The Commission approves Dominion's proposed costs for the Advanced Metering Infrastructure and Customer Information Platform projects.⁴¹ In addition, the Commission agrees with Staff that in proceedings where Dominion requests recovery of such costs, the Company shall – as part of its application – clearly and expressly identify any costs that exceed previously authorized cost caps, demonstrate the reasonableness of such costs, and request approval thereof.

LABOR O&M EXPENSE FACTOR

The Commission approves Dominion's Labor O&M Expense Factor of 55.451%, which is reasonably based on the three-year average from 2022-2024.⁴²

STORM EXPENSE NORMALIZATION

The Commission approves Dominion's continued use of a three-year average to normalize projected storm expenses for the rate years.⁴³

⁴⁰ See, e.g., Ex. 89 (Myers Direct) at 27-28; Ex. 105 (McLeod Rebuttal) at 27; Tr. 1469-70 (R. Smith), 1725-1726 (Myers).

⁴¹ See, e.g., Ex. 89 (Myers Direct) at 51-55; Ex. 105 (McLeod Rebuttal) at 15-18; Tr. 1771-1774 (Myers), 2107-2108 (McLeod).

⁴² See, e.g., Ex. 71 (R. Smith Direct) at 25-26; Ex. 108 (Lee Rebuttal) at 15-17.

⁴³ See, e.g., Ex. 71 (R. Smith Direct) at 41-45; Ex. 108 (Lee Rebuttal) at 23.

ANNUALIZED REVENUE AND CUSTOMER GROWTH

Unless otherwise modified by this Final Order, the Commission approves the annualized revenue and customer growth included by the Company.⁴⁴

OTHER CAPITAL INVESTMENTS AND DEPRECIATION/PROPERTY TAXES

Unless otherwise modified by this Final Order, the Commission approves Staff's adjustments to Other Capital Investments and Depreciation/Property Taxes.⁴⁵

CREDIT FACILITY FEES

The Commission approves Staff's adjustments to remove the increase to credit facility costs and fees resulting from Dominion's revised allocation methodology.⁴⁶

OTHER PAYROLL/BENEFITS

With the exception of the service company billing percentage addressed above, the Commission approves Staff's adjustments to the computation of payroll, benefits, incentive compensation, and payroll taxes.⁴⁷

NUCLEAR OUTAGE MAINTENANCE

The Commission approves Staff's adjustments to Nuclear Outage Maintenance costs.⁴⁸

⁴⁴ See, e.g., Ex. 88 (Otwell Supp.) at 1-2; Ex. 108 (Lee Rebuttal) at 9; Ex. 129 (Givens Rebuttal) at 6-9.

⁴⁵ See, e.g., Ex. 84 (Long Direct) at 24-29; Ex. 108 (Lee Rebuttal) at 11-12.

⁴⁶ See, e.g., Ex. 89 (Myers Direct) at 68-70; Ex. 108 (Lee Rebuttal) at 6.

⁴⁷ See, e.g., Ex. 83 (Clayton Direct) at 2-11.

⁴⁸ See, e.g., Ex. 83 (Clayton Direct) at 13-14; Ex. 85 (Long Supp.) at 4; Ex. 108 (Lee Rebuttal) at 17-18.

DEPRECIATION DEFERRAL-RELATED EXCESS DEFERRED INCOME TAXES

The Commission approves Staff's adjustments to project the amortization of Depreciation Deferral-Related Excess Deferred Income Taxes.⁴⁹

BELOW-THE-LINE COSTS

The Commission approves Staff's adjustments to remove "below-the-line" costs inadvertently recorded in the "above-the-line" operating accounts.⁵⁰

RIDER TRG PRICE DIFFERENTIAL REVENUES

The Commission approves Staff's adjustments to correct the market prices included in the computation of Rider TRG renewable energy certificate price differential revenues being removed from base rates.⁵¹

INTEREST INCOME

The Commission approves Staff's adjustments to Interest Income related to the Company's recent fuel securitization.⁵²

CAPITALIZED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The Commission approves Staff's recommendation to cease removal of pre-1991 capitalized allowance for funds used during construction from the revenue requirement.⁵³

⁴⁹ See, e.g., Ex. 84 (Long Direct) at 38-39; Ex. 108 (Lee Rebuttal) at 7.

⁵⁰ See, e.g., Ex. 89 (Myers Direct) at 70-73; Ex. 108 (Lee Rebuttal) at 6.

⁵¹ See, e.g., Ex. 87 (Otwell Direct) at 26-27; Ex. 108 (Lee Rebuttal) at 5.

⁵² See, e.g., Ex. 89 (Myers Direct) at 73; Ex. 108 (Lee Rebuttal) at 8.

⁵³ See, e.g., Ex. 84 (Long Direct) at 37-38; Ex. 108 (Lee Rebuttal) at 6.

CASH WORKING CAPITAL

The Commission approves Staff's adjustments to the cash working capital lead/lag study and balance sheet analysis, as well as the Company's request to begin recovering generation rate adjustment clause-related cash working capital in base rates (excluding Rider OSW).⁵⁴

UPDATED ELIMINATION OF RATE ADJUSTMENT CLAUSES

The Commission approves Staff's adjustments related to the elimination of rate adjustment clause-related costs from base rate cost of service..⁵⁵

COAL PLANT EXPENDITURES

The Commission finds that it is reasonable: (1) not to disallow certain coal plant O&M, capital, and environmental costs; and (2) not to require preapproval of capital investments attendant to the Company's coal plants.⁵⁶

OTHER REVENUES

Unless otherwise modified by this Final Order, the Commission approves Staff's adjustments to incorporate corrections reflecting the level of revenues that are reasonably predicted to occur during the rate years.⁵⁷

JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES

After almost a decade of flat-to-low growth, electricity consumption is forecast to increase markedly, and that increase is being driven by commercial and industrial customers—specifically, data centers. This evolution of the Company's load growth profile – in both source

⁵⁴ See, e.g., Ex. 84 (Long Direct) at 33-36; Ex. 108 (Lee Rebuttal) at 13, 24-25.

⁵⁵ See, e.g., Ex. 84 (Long Direct) at 6-7; Ex. 108 (Lee Rebuttal) at 5.

⁵⁶ See, e.g., Ex. 45 (Glick Direct) at 24-25; Ex. 119 (Green Rebuttal) at 10; Ex. 131 (Hinson Rebuttal) at 2-6; Tr. 935-936 (Glick).

⁵⁷ See, e.g., Ex. 87 (Otwell Direct) at 17-20; Ex. 129 (Givens Rebuttal) at 6-9.

and magnitude – make it appropriate at this time to begin the process of transitioning to a cost allocation methodology that takes this shift into account.

Accordingly, the Company shall develop – for consideration in its next biennial review – alternatives that transition away from the full Average & Excess (“A&E”) methodology for the allocation of plant costs. In its next biennial review, Dominion shall include class cost of service studies for the first step of this transition.⁵⁸ The Company, in consultation with Staff, shall investigate and develop three alternatives for such purpose. For example, one alternative shall be a modified A&E model that incorporates principles from a six-month (or higher) coincident peak allocation methodology. In addition, Dominion shall develop and prepare such studies in fully executable formats that can be fully replicated.

The Company’s A&E class cost of service study, updated to reflect the newly proposed GS-5 rate class, demonstrates that customers that will make up the GS-5 rate class contributed an overall per books rate of return of 6.28% for the end-of-test period ending December 31, 2024, which is the lowest return for all rate classes other than outdoor lighting.⁵⁹ With respect to the Company’s transmission function, the same study revealed that those same customers contributed a per books rate of return of 3.01%, which is the lowest return associated with the transmission function for all rate classes other than outdoor lighting.⁶⁰ The same study further

⁵⁸ This directive does not preclude participants in future proceedings from proposing alternative cost allocation methodologies.

⁵⁹ Ex. 126.

⁶⁰ *Id.* The Commission recognizes that transmission rates are currently set using a 12 coincident peak allocation methodology in the Company’s annual proceeding under Code § 56-585.1 A 4, whereas the cost of service studies presented in this proceeding are prepared using the Company’s A&E methodology, as illustrated in Ex. 126.

revealed that remaining GS-4 class customers pay relatively higher rates of return of 20.75% (overall per books) and 22.41% (transmission).⁶¹

Given the relatively low rate of return illustrated by the current cost of service study, with respect to the transmission function, for the new GS-5 rate class, the Commission anticipates examining transmission cost allocation in the next appropriate rate proceeding – the Company’s annual filing pursuant to Code § 56-585.1 A 4. Accordingly, and similar to the above, the Commission directs that the Company, in its next filing pursuant to Code § 56-585.1 A 4, shall develop and propose alternative cost allocations for such purpose. One alternative shall be the same modified A&E model that incorporates principles from a six-month (or higher) coincident peak allocation methodology. The statutory deadline for a Commission order pursuant to Code § 56.585.1 A 4 is compressed – three months from the date a petition is filed.⁶² Accordingly, the Commission directs a Staff-facilitated meeting, one-month in advance of the Company’s anticipated filing date, where interested parties may participate, and where the Company is encouraged to provide information regarding its investigation into alternative transmission cost allocation methodologies.

COST ALLOCATION, RATE DESIGN, AND TERMS AND CONDITIONS

REVENUE APPORTIONMENT

The Commission approves the Company’s proposed revenue apportionment for 2026 and 2027, as modified by Staff’s adjustments.⁶³ For the revenue requirement approved herein,

⁶¹ *Id.*

⁶² Code § 56-585.1 A 7.

⁶³ *See, e.g.*, Ex. 26 (Givens Direct) at Schedule 1; Ex. 98 (Blevins Direct) at 3-6, 35-36 (Tables 30 & 31).

Dominion shall proportionally adjust its revenue apportionment to maintain the relative percentages of revenue assigned to each customer class as recommended by Staff.⁶⁴

BASIC CUSTOMER CHARGES

As recommended by Staff, the Commission approves: (1) Dominion's proposed Basic Customer Charges for the GS-3, GS-4, and GS-5 customer classes; (2) the existing Basic Customer Charges for the Residential and GS-1 customer classes; and (3) Basic Customer Charges of \$31.90 and \$13.88 for the GS-2 and Church customer classes, respectively.⁶⁵

TIME-OF-USE RATES

The Commission approves Dominion's proposed time-of-use rates, except as modified by Staff's recommended changes to calculating the Basic Customer Charge.⁶⁶

GENERATION ADJUSTMENT DEMAND CHARGE

The Commission approves Dominion's rate design for Rate Schedules GS-2T, GS-3, 6, 6TS, and 10-Secondary, which includes the removal of the Generation Adjustment Demand Charge.⁶⁷

⁶⁴ See, e.g., Ex. 98 (Blevins Direct) at 38; Staff's Post-Hearing Brief at 48, n.249.

⁶⁵ See, e.g., Ex. 26 (Givens Direct) at 35-36, and Schedule 3; Ex. 98 (Blevins Direct) at 42-43, and Attachment RSB-4.

⁶⁶ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 26 (Givens Direct) at 38-39; Ex. 98 (Blevins Direct) at 42-43, 48-49.

⁶⁷ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 26 (Givens Direct) at 40; Ex. 98 (Blevins Direct) at 49-51.

OUTDOOR LIGHTING RATE SCHEDULE 28

The Commission approves Dominion's changes to Rate Schedule 28, as well as Staff's proposed adjustments thereto.⁶⁸

RATE SCHEDULE 1G

The Commission approves Dominion's proposal to make Schedule 1G a permanent tariff and to remove the 20,000 residential customer participation cap.⁶⁹ The Commission further directs the Company, as part of its compliance filing in this matter, to adjust the Schedule 1G rate design to be revenue neutral with Schedule 1.⁷⁰

RATE SCHEDULES MBR AND SCR

Rate Schedules MBR⁷¹ and SCR⁷² generally permit large loads – oftentimes data centers – to obtain generation service at a rate other than the cost-of-service rate. Rather, generation rates charged to Schedule MBR and SCR customers reflect the wholesale market rates – and not retail rates based on the Company's generation cost of service. To the extent that the applicable rate under Schedule MBR or SCR became significantly lower than the applicable cost-of-service rate for an extended period of time, this would result in such customers contributing less than their proportional share of revenues based on the standard tariff rates designed to serve such

⁶⁸ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 25 (Miller Direct) at 32, 35-38; Ex. 26 (Givens Direct) at 40-41; Ex. 98 (Blevins Direct) at 57-58.

⁶⁹ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 26 (Givens Direct) at 37-38; Ex. 97 (J. Ellis Direct) at 5-7.

⁷⁰ See, e.g., Ex. 97 (J. Ellis Direct) at 6-7; Ex. 129 (Givens Rebuttal) at 21-22; Tr. 1812 (J. Ellis).

⁷¹ Rate Schedule MBR is an experimental rate structured to reflect market-based rate pricing in the PJM wholesale market. Ex. 27 (Stuller Direct) at 10.

⁷² Rate Schedule SCR is a market-based pricing rate that is similar to MBR but only open to customers who are party to the SCR contract. Ex. 27 (Stuller Direct) at 12.

customers.⁷³ Moreover, customers eligible for Schedules MBR and SCR would have a clear financial incentive to migrate to such a lower rate in that circumstance. Staff and the Company agreed that cost shifting from Rate Schedules MBR and SCR customers to other customers can occur if two things happen: (i) MBR load is beyond Dominion's percentage of market purchases; and (ii) the MBR rate is lower than the standard tariff rate.⁷⁴ On the other hand, the Company and others testified that Rate Schedules MBR and SCR provide a natural hedge against the Company's short position on capacity and energy.⁷⁵ But, according to the Company, the benefits of the hedging effect exist only up to the amount of capacity and energy making up the Company's short position.⁷⁶

The Commission approves the Company's requests related to Rate Schedules MBR and SCR, subject to the following.⁷⁷ While not setting an explicit cap on participation in Rate Schedules MBR and SCR, the Commission expects that the Company will implement Rate Schedules MBR and SCR together in a reasonable and prudent manner, and not to the detriment of any other customers. To this end, the Company is directed to manage participation in Rate Schedules MBR and SCR so that they do not become oversubscribed such that the amount of participating load exceeds either the Company's short capacity or energy positions.⁷⁸ In

⁷³ See, e.g., Ex. 97 (Ellis Direct) at JAE-2.

⁷⁴ Tr. 742-743 (Gaskill), 1815 (Ellis), 2214-2215 (Gaskill).

⁷⁵ Ex. 27 (Stuller Direct) at 11; Tr. 1814 (Ellis).

⁷⁶ Tr. 742-744 (Company witness Gaskill describing an "overhedged" position).

⁷⁷ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 27 (Stuller Direct) at 12-13. The Commission denies further modifications to these rate schedules requested by respondents, including elimination of certain demand obligations. See, e.g., Ex. 41 (Bremser Direct) at 50; Ex. 55 (Lacey Direct) at 6-7, 47-48, 51; Tr. 848-849 (Bremser), 1124 (Lacey).

⁷⁸ See e.g., Tr. 1816-1817.

addition, the Company shall annually report to Staff the total customer load taking service under (1) Rate Schedule MBR, and (2) Rate Schedule SCR.

ADDITIONAL TARIFF CHANGES

The Commission approves Dominion's proposals: (1) to remove tariff language permitting meter reads in 10 kilowatt-hour increments;⁷⁹ (2) to remove references to Distribution kWh Charges for Non-Exempt Customers;⁸⁰ (3) to update the Monthly Facilities Charges, Interval Metering Charges, Installation/Removal Charges, Service Reconnection Charges, and Temporary Service Charges;⁸¹ and (4) to update the tax effect recovery factor (Rider D), subject to any modifications necessary based on the capital structure approved herein.⁸²

ADDITIONAL BIENNIAL REVIEW FINDINGS

As recommended by Staff, the Commission: (1) finds that the rates, tolls, charges, and schedules approved in this Final Order contain reasonable classifications of customers;⁸³ (2) approves the Company's proposed uprates to its Ladysmith, Remington, Bear Garden, and Possum Point units;⁸⁴ (3) directs Dominion to track, and to report annually to Staff, its solar fleet's availability factor over multiple years to better evaluate performance based on factors

⁷⁹ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 27 (Stuller Direct) at 5-6; Ex. 97 (J. Ellis Direct) at 2.

⁸⁰ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 27 (Stuller Direct) at 5, 7; Ex. 97 (J. Ellis Direct) at 3-4.

⁸¹ See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 27 (Stuller Direct) at 3-5; Ex. 97 (J. Ellis Direct) at 13-18.

⁸² See, e.g., Ex. 3 (Biennial Application) at Filing Schedule 41; Ex. 27 (Stuller Direct) at 5-6; Ex. 97 (J. Ellis Direct) at 10-11.

⁸³ See 2025 Va. Acts ch. 395. See, e.g., Ex. 103 (Pratt Direct) at 5-8.

⁸⁴ See, e.g., Ex. 8 (Green Direct) at 6-9; Ex. 81 (S. Smith Direct) at 10.

within the Company's control;⁸⁵ (4) directs Dominion to continue monitoring customer service performance to ensure that benefits of the new Customer Information Platform, Mobile App, and Redesigned Billing systems are realized, and that issues related thereto are reasonably resolved;⁸⁶ and (5) directs the Company to supplement its Filing Schedule 47 in future biennial review proceedings to provide a comparison of the trends in inflation with the trends in revenues generated from rate adjustment clauses under Code § 56-585.1 A 6.⁸⁷

LARGE LOAD INTERCONNECTION QUEUE

There was testimony at the hearing regarding the Company's new interconnection queue process for large load customers.⁸⁸ Although the Commission has exercised its discretion not to address comprehensive transmission planning or the allocation of transmission costs as part of this biennial review proceeding, we recognize, as noted in the concurrence of Case No. PUR-2024-00135, that such issues loom large.

Accordingly, in addition to directing an examination of cost allocation for transmission costs in the next appropriate transmission rate proceeding under Code § 56-585.1 A 4, the Commission further directs that the Company file its new large load interconnection queue process, along with supporting testimony, in a separate future proceeding at the Commission. The Commission finds that the public interest would be supported by a transparent process wherein the rules for the interconnection process of larger loads are subject to examination and approval in a formal proceeding. Other interested parties would have an opportunity to

⁸⁵ See, e.g., Ex. 96 (Joshapura Direct) at 11.

⁸⁶ See, e.g., Ex. 96 (Joshapura Direct) at 17-18.

⁸⁷ See, e.g., Ex. 98 (Blevins Direct) at 59; Tr. 1837-1839 (Blevins).

⁸⁸ Tr. 448-451 (Blackwell).

participate. The Commission anticipates that such a proceeding will occur on an expedited timeline and directs that the Company make such a filing on or before February 2, 2026. As part of its filing, the Commission encourages the Company to consider options allowing for faster interconnection of large loads that meet certain readiness or other reasonable criteria (*e.g.*, site readiness, proximity to generation, flexibility, etc.).

RATE SCHEDULE GS-5

The Company shall implement a new rate schedule, Rate Schedule GS-5, as set forth below, effective January 1, 2027. The Commission finds such to be just and reasonable, supported by the evidence, and permitted by law. Moreover, the Commission finds that the specific provisions approved herein reflect a reasonable classification and treatment of customers that are similarly situated based upon, among other things, cost causation and usage characteristics.⁸⁹

GS-5 RATE CLASS

The GS-5 rate class shall include customers with: (1) a measured or contracted demand of 25 megawatts (“MW”) or greater on a contiguous site; and (2) a measured or expected load factor of at least 75%.⁹⁰ The Commission likewise approves the Company’s proposals for: (a) measuring demand and load factor to determine if a customer falls within Rate Schedule

⁸⁹ Accordingly, unless specifically approved herein, the Commission has exercised its discretion (as supported by the record) to reject other proposals attendant to Rate Schedule GS-5, finding that such are neither legally nor factually necessary and that the provisions approved herein are reasonable.

⁹⁰ *See, e.g.*, Ex. 15 (Blackwell Direct) at 13; Ex. 20 (Haynes Direct) at 3-4; Ex. 27 (Stuller Direct) at Schedule 1; Ex. 114 (Blackwell Rebuttal) at 8-10. For purposes of analyzing the continued implementation of this new customer class, Dominion shall collect and submit the information recommended by APV in future biennial review proceedings. *See, e.g.*, APV’s Post-Hearing Brief at 10.

GS-5;⁹¹ and (b) permitting totalization at contiguous locations, but not aggregating accounts at the customer retail service level, for purposes of applying minimum demands.⁹²

CONTRACT

The contract provisions shall apply to customers taking initial service and signing an ESA on or after January 1, 2027.⁹³ The contract term shall be 14 years.⁹⁴ A customer may also include, within the contract term, a load ramp period not to exceed four years (with a minimum annual ramp of 20%).⁹⁵ If the customer continues to take service after the conclusion of the contract term, the minimum charges approved herein shall continue.⁹⁶ If the customer ceases operations or otherwise defaults on its agreement during the contract term, the customer shall be required to pay an exit fee covering any outstanding minimum charges over the remaining contract duration (subject to capacity reassignment as addressed below).⁹⁷

⁹¹ See, e.g., Ex. 15 (Blackwell Direct) at 13; Ex. 20 (Haynes Direct) at 3-4; Ex. 27 (Stuller Direct) at Schedule 1.

⁹² See, e.g., Ex. 27 (Stuller Direct) at Schedule 1; Ex. 111 (Gaskill Rebuttal) at 14-16; Ex. 130 (Stuller Rebuttal) at 9-10 and Rebuttal Schedule 2; Tr. 2200-2201 (Gaskill).

⁹³ See, e.g., Ex. 15 (Blackwell Direct) at 21-22; Ex. 114 (Blackwell Rebuttal) at 10-11; Ex. 130 (Stuller Rebuttal) at Rebuttal Schedule 2.

⁹⁴ See, e.g., Ex. 15 (Blackwell Direct) at 21-22; Ex. 114 (Blackwell Rebuttal) at 14-16; Ex. 130 (Stuller Rebuttal) at Rebuttal Schedule 2.

⁹⁵ See, e.g., Ex. 15 (Blackwell Direct) at 21-22; Ex. 114 (Blackwell Rebuttal) at 14-16; Ex. 130 (Stuller Rebuttal) at Rebuttal Schedule 2.

⁹⁶ See, e.g., Ex. 15 (Blackwell Direct) at 19; Tr. 2206-2207 (Gaskill).

⁹⁷ See, e.g., Ex. 15 (Blackwell Direct) at 22; Ex. 114 (Blackwell Rebuttal) at 17-18. To ensure that the minimum demand charges approved herein represent a firm contract floor, the Commission approves the additional exit fee provisions recommended by APV. See, e.g., Ex. 62 (Wilson) at 74-77. In addition, the Commission does not herein address how revenues from exit fees shall be treated in future rate proceedings; as recommended by Staff, in future biennial reviews Dominion shall report on all exit fee payments received and how the Company proposes to treat those payments for ratemaking purposes. See, e.g., Ex. 103 (Pratt Direct) at 21.

COLLATERAL REQUIREMENTS

The collateral requirements shall apply to customers taking initial service and signing an ESA on or after January 1, 2027.⁹⁸ The Commission approves the Company's proposed collateral requirement terms, including: (1) \$1.5 million/MW; (2) a reduction up to 70% based on the customer's established credit; (3) provisions for third-party guarantees and letters of credit; and (4) releasing 1/14th of the collateral requirement each year throughout the contract term.⁹⁹ In addition, cash collateral shall accrue interest while held by Dominion and shall be returned to the customer consistent with standard financial practices.¹⁰⁰

MINIMUM DEMAND CHARGES

The Commission approves Dominion's proposed minimum demand charges: (1) minimum distribution charge of 85% contracted demand; (2) minimum transmission charge of 85% contracted demand; and (3) minimum generation charge of 60% contracted demand.¹⁰¹

⁹⁸ See, e.g., Ex. 15 (Blackwell Direct) at 13, 15, 22-24; Ex. 114 (Blackwell Rebuttal) at 10-12; Ex. 130 (Stuller Rebuttal) at 10-11 and Rebuttal Schedule 2.

⁹⁹ See, e.g., Ex. 15 (Blackwell Direct) at 23-24; Ex. 111 (Gaskill Rebuttal) at 16-17; Ex. 114 (Blackwell Rebuttal) at 19-26; Ex. 130 (Stuller Rebuttal) at Rebuttal Schedule 2. The Commission clarifies that the specific collateral requirements required herein do not fall within, and are not precluded by, the general customer deposit provisions in 20 VAC 5-10-20. See, e.g., Dominion's Post-Hearing Brief at 3-4. Moreover, to the extent the Commission approves a specific tariff provision for a specific utility after notice and hearing, such supersedes any generally applicable regulation.

¹⁰⁰ See, e.g., Tr. 2373 (Blackwell).

¹⁰¹ See, e.g., Ex. 15 (Blackwell Direct) at 17-19; Ex. 27 (Stuller Direct) at 8-9 and Schedule 1; Ex. 111 (Gaskill Rebuttal) at 3-16; Ex. 130 (Stuller Rebuttal) at Rebuttal Schedule 2. In addition, while the Commission denies certain respondents' proposal to base the calculation of a customer's minimum demand obligations on a rolling 12-month average, we approve the request that Dominion include, in its Terms and Conditions, exemptions from minimum demand obligations to allow for necessary and planned maintenance. See, e.g., Ex. 40 (Joint High Load Proposal) at ¶ 2.d; Ex. 41 (Bremser Direct) at 37-39.

The Commission also approves the Company's proposal to exclude PJM capacity expense from the minimum generation demand charge.¹⁰²

Next, the Company has established that certain legacy customers present different risk and cost causation profiles, and the Commission approves the exemptions proposed by Dominion: (a) minimum demand charges shall not apply to a customer that was taking service from the Company prior to January 1, 2016; and (b) minimum generation demand charges shall not apply to a customer that as of January 1, 2025, was taking supply service from a competitive service provider ("CSP"), was a Schedule 10-Interruptible Service customer, or that formally notified the Company before January 1, 2025, that it intended to elect service from a CSP or under Schedule 10 prior to January 1, 2026.¹⁰³

Unless exempted per the above, the minimum generation demand charges shall apply to customers receiving service from a CSP.¹⁰⁴ Dominion must consider aggregate forecasted demand over a long-term planning period, must plan to meet those needs with supply resources that typically require many years to develop, and must construct generation to be ready to serve high load customers who are eligible to select a CSP in the future.¹⁰⁵ Accordingly, the Commission finds that the minimum generation demand charges shall apply to these new shopping customers. This will reasonably recover the fixed costs of the infrastructure that must

¹⁰² See, e.g., Ex. 111 (Gaskill Rebuttal) at 9-10.

¹⁰³ See, e.g., Ex. 15 (Blackwell Direct) at 18-19; Ex. 27 (Stuller Direct) at Schedule 1; Ex. 129 (Givens Rebuttal) at 36-37; Tr. 2188-2189 (Gaskill).

¹⁰⁴ The Commission also concludes that this finding is not inconsistent with the Company's currently approved Terms & Conditions of service. See, e.g., Dominion's Post-Hearing Brief at 37-38; Tr. 2406-2408 (Blackwell).

¹⁰⁵ See, e.g., Ex. 15 (Blackwell Direct) at 3-7; Ex. 111 (Gaskill Rebuttal) at 3-8; Tr. 2175, 2178-2181 (Gaskill); Dominion's Post-Hearing Brief at 34-35.

be available to serve those very same customers regardless of whether they choose to receive service from a CSP in the future.¹⁰⁶

CAPACITY REDUCTIONS

A customer on Rate Schedule GS-5 may reduce its contracted capacity during the contract term: (1) by up to 20% at no cost; and (2) by an additional 30% if another customer agrees to assume the associated capacity.¹⁰⁷ Each capacity reduction shall require a separate 36-month notice.¹⁰⁸ In addition, the Commission agrees that, prior to the effective date, existing customers who would be subject to the High Load Customer Terms and Conditions be allowed to adjust their contracted demand downward (one-time) without penalty.¹⁰⁹ Dominion shall track the total amount of capacity reductions and reassignments requested and implemented as of the date of this Final Order and shall provide Staff with an aggregated annual report identifying the same.¹¹⁰

Accordingly, IT IS ORDERED THAT:

(1) The Company's Application is granted in part and denied in part as set forth in this Final Order.

¹⁰⁶ See, e.g., Ex. 15 (Blackwell Direct) at 8-9, 18-19; Ex. 111 (Gaskill Rebuttal) at 3-8, 13-14; Dominion's Post-Hearing Brief at 42-43. The Commission further concludes that such finding is not prohibited by state or federal law. See, e.g., Dominion's Oct. 24, 2025, Brief Legal Memorandum.

¹⁰⁷ See, e.g., Ex. 15 (Blackwell Direct) at 19-21; Ex. 114 (Blackwell Rebuttal) at 12-14. The Company's currently available methods to reduce capacity shall continue until Rate Schedule GS-5 becomes effective. See, e.g., Ex. 15 (Blackwell Direct) at 20; Ex. 114 (Blackwell Rebuttal) at 14.

¹⁰⁸ See, e.g., Ex. 15 (Blackwell Direct) at 19-21. Customers may take direct actions to facilitate reassignment of unneeded capacity, including full contract reassignment accepting the current contract terms. See, e.g., Ex. 40 (Joint High Load Proposal) at ¶ 7.d; Tr. 453-457 (Blackwell). The Commission does not at this time direct the development of a dispute resolution process regarding capacity requests and reassignments.

¹⁰⁹ See, e.g., DCC's Post-Hearing Brief at v.

¹¹⁰ The Commission does not at this time rule on whether such information shall be deemed confidential, as well as to which future proceeding(s) such information may be deemed relevant.

(2) The Company shall comply with the directives set forth in this Final Order.

(3) For approved tariff changes effective January 1, 2026, the Company shall forthwith file revised tariffs and terms and conditions of service and supporting workpapers with the Clerk of the Commission and with the Commission's Divisions of Public Utility Regulation and Utility Accounting and Finance, as necessary to comply with the directives and findings set forth in this Final Order. The Clerk of the Commission shall retain such filing for public inspection in person and on the Commission's website: scc.virginia.gov/pages/Case-Information.

(4) For approved tariff changes effective January 1, 2027, the Company shall file revised tariffs and terms and conditions of service and supporting workpapers with the Clerk of the Commission and with the Commission's Divisions of Public Utility Regulation and Utility Accounting and Finance, at least forty-five (45) days in advance of such effective date, as necessary to comply with the directives and findings set forth in this Final Order. The Clerk of the Commission shall retain such filing for public inspection in person and on the Commission's website: scc.virginia.gov/pages/Case-Information.

(5) This case is dismissed.

A COPY hereof shall be sent electronically by the Clerk of the Commission to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

Final Order Revenue Requirement Reconciliation - 2026 Rate Year
(In Thousands of Dollars)

Line No.	Issue	Incremental Revenue Requirement		
		Combined	Generation	Distribution
1	Company Application (including Purchased Capacity Expense)	\$821,962	\$421,411	\$400,551
2	Company Rebuttal Adjustments	(\$115,129)	(\$105,625)	(\$9,505)
3	Company Rebuttal (including Purchased Capacity Expense)	\$706,833	\$315,787	\$391,046
4	Capital Structure and Cost of Capital	(\$957)	(\$409)	(\$548)
5	Return on Equity	(\$65,151)	(\$27,812)	(\$37,339)
6	Service Company Billing Percentage	-	-	-
7	DSM-EE and VO Sales Reductions	(\$8,694)	(\$5,459)	(\$3,235)
8	Offshore Wind Investment Tax Credits	(\$23,579)	(\$23,579)	-
9	Data Center Capital Expenditures and Revenues	(\$10,685)	(\$2,689)	(\$7,996)
10	Power Delivery O&M Expenses	-	-	-
11	Fossil and Hydro Planned Outage Expenses	(\$10,924)	(\$10,924)	-
12	Deferred Fuel Balance	-	-	-
13	Power Generation Capital Spend	(\$8,480)	(\$8,480)	-
14	Nuclear Production Tax Credit	(\$3,263)	(\$3,263)	-
15	Grid Transformation Plan Benefits	-	-	-
16	Non-Recurring Customer Accounts Expense	(\$4,688)	-	(\$4,688)
17	Purchased Capacity Regulatory Asset	(\$4,515)	(\$4,515)	-
18	Advanced Metering Infrastructure and Customer Information Platform	-	-	-
19	Labor O&M Expense Factor	-	-	-
20	Storm Expense Normalization	-	-	-
21	Other Payroll/Benefits	(\$295)	(\$205)	(\$90)
22	Nuclear Outage Maintenance	\$31	\$31	-
23	Cash Working Capital	\$60	\$230	(\$171)
24	Coal Plant Expenditures	-	-	-
25	Other Revenues	(\$26)	(\$4,455)	\$4,429
26	Commission-Authorized 2026 Incremental Revenue Requirement	\$565,667	\$224,259	\$341,408

Final Order Revenue Requirement Reconciliation - 2027 Rate Year
(In Thousands of Dollars)

Line No.	Issue	Incremental Revenue Requirement		
		Combined	Generation	Distribution
1	Company Application (including Purchased Capacity Expense)	\$1,166,962	\$628,897	\$538,065
2	Company Rebuttal Adjustments	(\$203,696)	(\$198,550)	(\$5,145)
3	Company Rebuttal (including Purchased Capacity Expense)	\$963,266	\$430,347	\$532,920
4	Capital Structure and Cost of Capital	(\$1,025)	(\$416)	(\$608)
5	Return on Equity	(\$69,744)	(\$28,340)	(\$41,403)
6	Service Company Billing Percentage	-	-	-
7	DSM-EE and VO Sales Reductions	(\$12,088)	(\$7,660)	(\$4,428)
8	Offshore Wind Investment Tax Credits	(\$23,579)	(\$23,579)	-
9	Data Center Capital Expenditures and Revenues	(\$38,413)	(\$12,854)	(\$25,559)
10	Power Delivery O&M Expenses	-	-	-
11	Fossil and Hydro Planned Outage Expenses	(\$9,682)	(\$9,682)	-
12	Deferred Fuel Balance	-	-	-
13	Power Generation Capital Spend	(\$15,683)	(\$15,683)	-
14	Nuclear Production Tax Credit	(\$7,580)	(\$7,580)	-
15	Grid Transformation Plan Benefits	-	-	-
16	Non-Recurring Customer Accounts Expense	(\$4,688)	-	(\$4,688)
17	Purchased Capacity Regulatory Asset	(\$4,515)	(\$4,515)	-
18	Advanced Metering Infrastructure and Customer Information Platform	-	-	-
19	Labor O&M Expense Factor	-	-	-
20	Storm Expense Normalization	-	-	-
21	Other Payroll/Benefits	(\$372)	(\$259)	(\$113)
22	Nuclear Outage Maintenance	(\$211)	(\$211)	-
23	Cash Working Capital	(\$37)	\$90	(\$127)
24	Coal Plant Expenditures	-	-	-
25	Other Revenues	(\$37)	\$1,999	(\$2,035)
26	Commission-Authorized 2027 Incremental Revenue Requirement	\$775,612	\$321,655	\$453,957
27	Less: Commission-Authorized 2026 Incremental Revenue Requirement	\$565,667	\$224,259	\$341,408
28	Commission-Authorized 2027 Rate Year Revenue Increase	\$209,946	\$97,397	\$112,549

EXHIBIT B

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**



In the Matter of the Application of Evergy)
Metro, Inc. d/b/a Evergy Missouri Metro)
and Evergy Missouri West, Inc. d/b/a)
Evergy Missouri West for Approval of New)
and Modified Tariffs for Service to Large)
Load Customers)

Case No. EO-2025-0154

REPORT AND ORDER

Issue Date: November 13, 2025

Effective Date: December 13, 2025

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Application of Evergy)
Metro, Inc. d/b/a Evergy Missouri Metro and)
Evergy Missouri West, Inc. d/b/a Evergy)
Missouri West for Approval of New and)
Modified Tariffs for Service to Large Load)
Customers)

Case No. EO-2025-0154

APPEARANCES

EVERGY MISSOURI METRO, INC. D/B/A EVERGY MISSOURI and EVERGY MISSOURI WEST, INC. D/B/A EVERGY MISSOURI WEST:

Cole Bailey, 1200 Main Street, Kansas City, Missouri 64105.

Jacqueline Whipple, 4520 Main Street, Suite 1100, Kansas City, Missouri 64111.

James Fischer, 2081 Honeysuckle Lane, Jefferson City, Missouri 65109.

Chandler Hiatt, 4520 Main Street, Suite 1100, Kansas City, Missouri 64111.

STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION:

Andrea Hansen, Legal Counsel, P.O. Box 2230, 200 Madison Street, Suite 800, Jefferson City, Missouri 65102.

Travis Pringle, Chief Deputy Counsel, P.O. Box 2230, 200 Madison Street, Suite 800, Jefferson City, Missouri 65102.

Alexandra Klaus, Senior Counsel, P.O. Box 2230, 200 Madison Street, Suite 800, Jefferson City, Missouri 65102.

OFFICE OF THE PUBLIC COUNSEL:

John Clizer, 200 Madison Street, Suite 650, P.O. Box 2230, Jefferson City, Missouri 65102.

UNION ELECTRIC COMPANY D/B/A AMEREN MISSOURI:

James Lowery, 9020 S. Barry Road, Columbia, Missouri 65203.

Wendy Tatro, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Paula Johnson, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

RENEW MISSOURI ADVOCATES D/B/A RENEW MISSOURI:

Nicole Mers, 501 Fay Street, Suite 206, Columbia, Missouri 65201.

NUCOR STEEL SEDALIA, LLC:

Marc Ellinger, Ellinger Bell, 308 E. High Street, Suite 300, Jefferson City, Missouri 65101.

VELVET TECH SERVICES, LLC:

Stephanie Bell, Ellinger Bell, 308 E. High Street, Suite 300, Jefferson City, Missouri 65101.

GOOGLE LLC:

Andrew Schulte, Polsinelli Law Firm, 900 W. 48th Place, Suite 900, Kansas City, Missouri 64112.

Frank Caro, Polsinelli Law Firm, 900 W. 48th Place, Suite 900, Kansas City, Missouri 64112.

Jared Jevons, Polsinelli Law Firm, 900 W. 48th Place, Suite 900, Kansas City, Missouri 64112.

DATA CENTER COALITION:

Nikhil Vijaykar, 4457 Howe Street, Oakland, California 94611.

Alissa Greenwald, 1580 Lincoln Street, Suite 1105, Denver, Colorado 80203.

SIERRA CLUB:

Sarah Rubenstein, 319 N. 4th Street, Suite 800, St. Louis, Missouri 63102.

THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY:

Diana C. Carter, 428 E. Capitol Avenue, Suite 303, Jefferson City, Missouri 65101.

Regulatory Law Judge: **Karolin Walker**

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REPORT AND ORDER

The Missouri Public Service Commission (Commission) having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Procedural History

On February 14, 2025, Evergy Metro, Inc. d/b/a Evergy Missouri Metro (EMM) and Evergy Missouri West, Inc. d/b/a Evergy Missouri West (EMW) (collectively “Evergy”) filed an *Application for Approval of Evergy’s Large Load Power Service (LLPS) Rate Plan and Associated Tariffs* (Application) requesting rates and tariffs for customers with loads larger than 100 megawatts (MW) in Evergy’s service areas. Along with its Application, Evergy filed direct testimony. Notice was issued and the following parties, listed in order, were granted intervention: Data Center Coalition (DCC), Nucor Steel Sedalia, LLC (Nucor), Velvet Tech Services, LLC (Velvet), Google LLC (Google), Sierra Club, Renew Missouri Advocates d/b/a Renew Missouri (Renew Missouri), Union Electric Company d/b/a Ameren Missouri (Ameren), and Empire District Electric Company d/b/a Liberty (Liberty) (collectively referred to as “Intervenors”). The Staff of the Commission (Staff) and the Office of the Public Counsel (OPC) also participated as parties in the case.

On May 13, 2025, an order setting a procedural schedule was issued. On July 25, 2025, the parties filed rebuttal testimony. On September 12, 2025, the parties

filed surrebuttal testimony. On September 18, 2025, Staff, on behalf of the parties, filed a list of issues, order of opening statements, list and order of witnesses, and order of cross-examination.

On September 25, 2025, Evergy, Ameren, Google, Velvet, Nucor, DCC, Renew Missouri, and Sierra Club, (collectively, the “Signatories”) filed a document titled *Non-Unanimous Global Stipulation and Agreement* (Agreement). Staff, OPC, and Liberty were not signatories to the Agreement, though the Agreement indicated that Liberty did not object. On September 29, 2025, Staff filed objections to the Agreement. Pursuant to Commission Rule 20 CSR 4240-2.115(2)(D), a stipulation and agreement that is objected to may become the position statement of the signatories.

An evidentiary hearing was held on September 30, 2025, through October 1, 2025, during which testimony was heard and the exhibits admitted giving all parties an opportunity to be heard by the Commission.

After the hearing, initial briefs were filed on October 29, 2025, and reply briefs on November 5, 2025. Additionally, the Application and Agreement were admitted into the record without objection on November 10, 2025, as Commission Exhibits A and B, respectively.

Evergy filed this case to comply with Section 393.130.7, RSMo, as set forth in SB4.¹ That section, in part, requires large electrical utilities to file a schedule to include in its service tariff containing rates to charge large load customers. Economic development was one of the main purposes of SB4. At the signing of SB4, Governor Mike Kehoe stated:

¹ SS#2 SB4, First Regular Session of the 103rd General Assembly, effective August 28, 2025.

"With this legislation, Missouri is well-positioned to attract new industry, support job growth, and maintain affordable, reliable energy for our citizens."

Staff's Proposal and the Agreement

The Commission has been presented with two proposals. First, Evergy and the other Signatories present their Agreement as the resolution to this case. The Agreement addressed a majority of the issues the parties put forth in the List of Issues for the Commission's determination. Second, Staff presented its own proposal to resolve this case.

The parties may propose issues for the Commission's determination, but the Commission ultimately decides the issues that are appropriate to address in its order. Having reviewed the evidence regarding the two proposals to determine if they satisfy the newly enacted law for schedules to serve large load customers, the Commission has determined the terms of the Agreement are the appropriate resolution to this case and it should be approved as to the issues it addresses.

Findings of Fact

General Findings of Fact

1. EMM is a Missouri corporation and is an "electrical corporation" and "public utility" as defined by Section 386.020, RSMo, and is authorized to provide electric service to portions of Missouri.²

² Exhibit A, Application, paragraph 1.

2. EMM is engaged in the generation, transmission, distribution and sale of electricity in western Missouri and eastern Kansas and operates primarily in the Kansas City metropolitan area.³

3. EMW is a Delaware corporation and is an “electrical corporation” and “public utility” as defined by 386.020, RSMo, and is authorized to provide electric service to portions of Missouri.⁴

4. EMW is engaged in the generation, transmission, distribution and sale of electricity in western Missouri, including suburban Kansas City, St. Joseph, and surrounding counties.⁵

5. OPC is a party to this case pursuant to Section 386.710(2), RSMo, and by Commission Rule 20 CSR 4240-2.010(10).

6. Staff is a party to this case pursuant to 20 CSR 4240-2.010(10).

Data Centers

7. Data centers are facilities that house computing machines, and related hardware and software. They provide the essential digital infrastructure that supports the applications, platforms and services people rely on every day.⁶

8. Data centers are not just large consumers of power; they are economic and operational partners that provide important advantages to electric utilities and their customers. The operational advantages of data centers are numerous and include:

- a. Data centers are consistent and predictable consumers of energy, which supports more efficient operation and planning of the electric utility grid;

³ Ex. A, Application, para. 1.

⁴ Ex. A, Application, para. 2.

⁵ Ex. A, Application, para. 2.

⁶ Ex. 400, Higgins Rebuttal, Page 4.

- b. Data centers enable utility system planners and grid operators to optimize existing generation and transmission infrastructure, which can delay new infrastructure investments and improve overall system efficiency; and
- c. Many large load customers engage in demand management, which further enhances grid stability and reliability.⁷

9. The economic advantage associated with data centers is that their consistent energy usage helps distribute fixed costs across a larger energy volume, which contributes to a lower average cost per kilowatt-hour for all customers.⁸

10. Some data centers, including Google, are engaging in strategic initiatives to develop long-term energy storage and improve data center demand-side flexibility, which can provide operational benefits to electric utilities and their customers.⁹

11. Google and other data center developers are also investing in advanced transmission technologies. For example, Google recently announced an initiative to accelerate deployment of next-generation transmission technology—specifically advanced conductors—across the U.S. electric grid to enhance the capacity of existing transmission lines at a fraction of the cost of installing new transmission infrastructure.¹⁰

12. Data centers support customers in many industries, including healthcare, financial services, transportation, and e-commerce.¹¹

⁷ Ex. 550, Berry Rebuttal, Page 8.

⁸ Ex. 550, Berry Rebuttal, Page 8.

⁹ Ex. 550, Berry Rebuttal, Pages 8-9.

¹⁰ Ex. 550, Berry Rebuttal, Page 9.

¹¹ Ex. 402, Higgins Surrebuttal, Pages 18-19.

13. AI technology, combined with the widescale electrification of various industries, and policy and security desires to domestically locate many of the data centers and manufacturing plants needed to support these advancements, is driving significant electric load growth across the country and globe.¹²

The Agreement

14. On September 25, 2025, Evergy, Ameren, Google, Velvet, Nucor, DCC, Renew Missouri, and Sierra Club, filed their *Non-Unanimous Global Stipulation and Agreement*.¹³

15. The Signatories ask the Commission to approve Evergy's LLPS Rate Plan as modified by the Agreement.¹⁴

16. Staff objected to parts of the Agreement.¹⁵

17. A majority of the issues put forth for the Commission's determination are addressed in the Agreement.¹⁶

18. The emerging industry standard for tariffs to serve LLPS customers prioritizes the establishment of terms and conditions to ensure large load customers contribute their fair share of costs and minimize risk to other customers if anticipated large load growth fails to materialize following significant investments.¹⁷

19. Common terms and conditions adopted in emerging tariffs include a contract term, a threshold size for applicability, minimum demand or bill charges, collateral requirements, provisions for reducing contract capacity and exiting, and options

¹² Ex. 100, Gunn Direct, Page 4.

¹³ Ex. B, Non-Unanimous Global Stipulation and Agreement, filed September 25, 2025.

¹⁴ Non-Unanimous Global Stipulation and Agreement, Pages 1-2.

¹⁵ Staff's Objections to the Non-Unanimous Stipulation and Agreement, filed September 29, 2025.

¹⁶ Ex. B, Non-Unanimous Global Stipulation and Agreement, filed September 25, 2025.

¹⁷ Ex. 551, Berry Surrebuttal, Pages 7-8.

for clean energy. Changes in rate design are generally minor. As a package these terms and conditions ensure, to an acceptably high degree, that the rates paid by large load customers reflect their representative share of costs.¹⁸

20. The LLPS Proposal outlined in the Agreement incorporates a definite and clear description of service/contract term requirements. Specifically, service under the proposed Schedule LLPS shall be for a minimum term that includes up to five years of an optional transitional load ramp period plus twelve years (the “Term”). The Term under the proposed schedule will commence on the date permanent service begins, or as set forth in the LLPS Service Agreement. During the transitional load ramp period, the customer’s maximum load may be lower than 75 MW.¹⁹

21. The LLPS Proposal outlined in the Agreement incorporates a definite and clear eligibility threshold of 75 MW, that is even broader than the minimum 100 MW threshold set out in SB4.²⁰

22. Under the LLPS Proposal outlined in the Agreement, a LLPS Service Agreement must include a Contract Capacity schedule specifying the customer’s forecasted annual steady-state peak load requirement for the post-load ramp period of the Term. The Contract Capacity schedule shall also specify the peak load requirement during the load ramp, if any.²¹

¹⁸ Ex. 551, Berry Surrebuttal, Pages 7 and 8.

¹⁹ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 6.

²⁰ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 2.

²¹ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 4.

23. The LLPS Proposal outlined in the Agreement incorporates detailed, definite and clear provisions for clear minimum demand, reducing contract capacity, and assessing capacity reduction charges.²²

24. The LLPS Proposal outlined in the Agreement incorporates detailed, definite and clear provisions for exiting or changing rate schedules and assessing applicable charges. One key provision is the requirement that in order to terminate or change rate schedules before the end of the Term or any Extension Term, the customer must provide written notice 36 months prior to the requested date of termination or schedule change. In such circumstance, the customer would be subject to an exit fee equal to the nominal value of the Minimum Monthly Bill times the number of months remaining in the Term or Extension Term, or for 12 months, whichever is greater (the “Exit Fee”). An additional fee would apply if the customer seeks to terminate with less than 36-months’ notice (the “Early Termination Fee”). In such case, the Early Termination Fee shall be equal to the Exit Fee plus two times the nominal value of the Minimum Monthly Bill times the number of months, less than the 36-months’ notice required for termination.²³

25. The LLPS Proposal outlined in the Agreement incorporates minimum monthly bill provisions based on minimum demand and bill charges. Specifically, customers taking service under Schedule LLPS shall be subject to a Minimum Monthly Bill that includes and is the sum of each of the following charges:

- a. Demand Charge (with minimum monthly demand set at 80 percent of the Contract Capacity (“Minimum Demand”));

²² Ex. B, Non-Unanimous Global Stipulation and Agreement, Pages 4-5.

²³ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 4.

- b. Customer Charge (metering, billing, customer support);
- c. Grid Charge (substation and transmission-related costs, exclusive of direct customer-owned substation and transmission-related costs) (for purposes of the Grid Charge, Grid Demand shall be the higher of: (a) the Monthly Maximum Demand occurring in the last 12 months including the then-current month or (b) the Minimum Demand);
- d. Reactive Demand Adjustment (where Evergy may determine the customer's monthly maximum 15-minute reactive demand in kilovars. The maximum reactive demand shall be computed similarly to the Monthly Maximum Demand, as set forth in Schedule LLPS);
- e. Other Demand-Based Riders approved by the Commission in the future; and,
- f. The Cost Stabilization Rider, with minimum monthly demand set at the Minimum Demand.²⁴

26. The LLPS Proposal outlined in the Agreement incorporates detailed collateral and security requirements. Those requirements include in part that: (i.) at the time of executing their LLPS Service Agreement, a Schedule LLPS customer must provide collateral in an amount equal to two (2) years of Minimum Monthly Bills, as calculated by Evergy (the "Collateral Requirement"); (ii.) any Collateral Requirement would be recomputed quarterly based upon the customer's rolling twenty-four (24)-month load forecast; (iii.) an LLPS customer may be exempted from twenty-five (25) to sixty (60) percent of the Collateral Requirement if they meet specific credit rating and liquidity

²⁴ Ex. B, Non-Unanimous Global Stipulation and Agreement, Pages 9-10.

requirements; and (iv.) no interest will accrue on any collateral held by Evergy under the Collateral Requirement.²⁵

27. The LLPS Proposal outlined in the Agreement incorporates definite and clear options for clean energy. Specifically, it incorporates four new optional clean and renewable energy riders that would be available to LLPS customers meeting specific requirements and allow them to participate in specific programs, the cost of which would be borne by the participating LLPS customer and/or Evergy.²⁶

28. The LLPS Proposal outlined in the Agreement would require any customer receiving service under Evergy's Economic Development Riders to be subject to a Cost Stabilization Rider. The Cost Stabilization Rider would be a new rider that would be updated annually and designed to ensure costs incurred to serve Schedule LLPS customers are recovered from those same customers.²⁷

29. Under the LLPS Proposal outlined in the Agreement, for extensions of transmission or substation facilities, any LLPS customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions. These costs will not include any resulting network upgrade costs for facilities classified as transmission under the Southwest Power Pool (SPP) Open Access Transmission Tariff.²⁸

30. SPP oversees the bulk electric system and administers the wholesale power market on behalf of a group of electric utilities, including EMM and EMW.²⁹

²⁵ Ex. B, Non-Unanimous Global Stipulation and Agreement, Pages 12-15.

²⁶ Ex. B, Non-Unanimous Global Stipulation and Agreement, Pages 18-20.

²⁷ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 10.

²⁸ Ex. B, Non-Unanimous Global Stipulation and Agreement, Page 21.

²⁹ Ex. 201, Staff Report and Recommendation, Page 15.

31. The Agreement establishes reasonable protections and safeguards for Evergy's existing customers, ensures that new large load customers will pay their share of system costs associated with serving new large loads, and provides a competitive rate program that will help drive economic development in Missouri.³⁰

32. The Signatories to the Agreement represent a broad range of diverse stakeholder interests including multiple large load customer interests (Google, Velvet, and DCC), conservation interests (Sierra Club and Renew Missouri) and utility interests (Evergy and Ameren).³¹

33. As modified by the Agreement, the LLPS Rate Plan requires large load customers to enter enforceable long-term service commitments, bearing substantial financial risk, and also be assessed rates that will recover the costs to serve large load customers, while providing ratemaking benefits to non-large load customers with opportunities for additional revenues and contributions from large load customers' participation in a suite of riders.³²

34. The commercial terms and conditions agreed to in the Agreement establish safeguards for non-LLPS customers with a minimum bill requirement, substantial minimum demand requirements, a minimum service term, and the creation of the Schedule LLPS customer class.³³

35. The Agreement is broadly consistent with emerging national trends in tariffs for service to large load customers, including the settlement recently reached by Evergy Metro, Inc. d/b/a Evergy Kansas Metro, Evergy Kansas South, Inc., and Evergy Kansas

³⁰ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Page 2.

³¹ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Page 18.

³² Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Page 17.

³³ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Pages 17-20.

Central, Inc., with all of the parties in the large load tariff case in their Kansas service territory.³⁴

36. The Agreement includes mechanisms to provide protection for other ratepayers if a large load customer terminates its service agreement before the end of the minimum service term, including requirements that the LLPS customer post and maintain collateral and pay a substantial exit fee in the event of termination.³⁵

37. The Cost Stabilization Rider and the Demand Charges are intended to capture incremental transmission and/or interconnection, facilities, and capacity costs driven by large load customers and then apportion costs to them.³⁶

38. Minimum bill commitments and credit standards set out in the Agreement reduce stranded cost and cross subsidy risks.³⁷

39. The riders, especially the renewable riders, set out in the Agreement allow the large data centers to achieve their sustainability targets.³⁸

Staff's Exemplar Tariff Proposal

40. Staff rejected Evergy's LLPS proposal, proposed an alternative LLPS proposal, and offered an exemplar tariff proposal consisting of a new rate design, terms and conditions, and riders.³⁹

41. Staff's proposal creates a barrier to economic development in Missouri and is far outside of the industry norm for similar tariffs.⁴⁰

³⁴ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Page 17.

³⁵ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Pages 17-18.

³⁶ Ex. 106, Gunn Testimony in Support of Stipulation and Agreement, Pages 10-14.

³⁷ Transcript Vol. II, Pages 17-18.

³⁸ Transcript Vol. III, Pages 131-132.

³⁹ Ex. 105, Lutz Surrebuttal, Page 25.

⁴⁰ Transcript Vol. III, Page 126, and Ex. 105, Lutz Surrebuttal, Page 25.

Industry Norms

42. Staff's proposal was developed without the benefit of an engagement process with large load customers or utilities or stakeholders, or a thorough analysis of comparable tariffs from other jurisdictions.⁴¹

43. Staff's proposal is fundamentally different from emerging industry standards for LLPS tariffs because it focuses on a redesign of rates, while the emerging industry standard prioritizes the establishment of terms and conditions to ensure large load customers contribute their share of costs and minimize risk to other customers if anticipated large load growth fails to materialize following significant investments.⁴²

44. While Staff's proposal includes an eligibility threshold, a contract term, and a collateral requirement, it fails to include minimum demand or bill charges, options to reduce contract capacity, or options to secure renewable or clean energy, which are all key components of the emerging standard for large load terms and conditions.⁴³

Complex Structure with Economic Implications

45. The design of Staff's proposal is complex.⁴⁴ The rate structure includes distinct pricing for 25 rate elements, and many of the rate elements depend on tracking deviations to execute the billing. This would complicate billing and tariff administration.⁴⁵

46. Staff's proposal creates rate instability for large load customers.⁴⁶

⁴¹ Ex. 551, Berry Surrebuttal, Page 6, and Transcript Vol. 2, Pages 213-215.

⁴² Ex. 551, Berry Surrebuttal, Pages 7 and 8.

⁴³ Ex. 551, Berry Surrebuttal, Page 9.

⁴⁴ Ex. 105, Lutz Surrebuttal, Page 29 and Ex. 704, Wills Surrebuttal, Pages 12-15.

⁴⁵ Ex. 105, Lutz Surrebuttal, Pages 29-30.

⁴⁶ Ex. 551, Berry Surrebuttal, Pages 4, 19, and 20.

47. Under Staff's proposal, it is unclear how a large load customer, or Evergy on behalf of the large load customer, could confidently model the expected rate to inform their site selection efforts, which could drive away large load customers from the state.⁴⁷

48. Staff's proposal imposes new costs and requirements on large load customers with little acknowledgment of the significant benefits they contribute to the broader system.⁴⁸

49. Staff's proposal is unduly discriminatory in its proposed treatment of each large load customer as a separate commercial pricing node.⁴⁹ Staff's proposed rate structure would add administrative burdens of separately registering large loads in energy markets to track very minor categories of cost.⁵⁰

50. Under Staff's proposed framework, large load customers face charges disconnected from actual costs and are denied any viable pathway to achieving their clean energy goals.⁵¹

51. Staff's proposal is very prescriptive and restricts Evergy's ability to exercise reasonable discretion in serving large load customers, whose needs are often highly individualized and not amenable to a one-size-fits-all approach.⁵²

52. If every aspect of service must be pre-approved through a lengthy regulatory process, as proposed by Staff, utilities would lose the ability to respond quickly with flexibility to large load customer requests. This may result in delays that cause prospective large load customers to seek opportunities in other states with more agile

⁴⁷ Ex. 105, Lutz Surrebuttal, Pages 29-30.

⁴⁸ Ex. 551, Berry Surrebuttal, Pages 4- 5.

⁴⁹ Ex. 551, Berry Surrebuttal, Pages 4, 10, and 13.

⁵⁰ Ex. 704, Wills Surrebuttal, Page 18.

⁵¹ Ex. 551, Berry Surrebuttal, Page 5.

⁵² Ex. 104, Gunn Surrebuttal, Page 8.

regulatory environments, thus decreasing Missouri's economic development opportunities.⁵³

53. Exit fees exist to ensure a long-term revenue stream is available to provide a fair contribution to the costs of long-lived assets. Given the size of the investments that may be accelerated to serve a large load customer, such fees could be substantial.⁵⁴

54. Staff's proposal includes an automatic trigger of exit fees any time a large load customer's demand falls below 50 percent of their contract demand for three consecutive months.⁵⁵

55. A three-month reduction in usage by a large load customer would not be a clear indication of a permanent termination of service.⁵⁶

56. Automatically requiring a large load customer to pay potentially substantial exit fees immediately following a three-month reduction in usage irrespective of whether the customer intends to continue operations in the service territory is not reasonable.⁵⁷

57. Staff's proposal risks diminishing the incentive for large load customers to invest in and locate in Missouri. From an electrical infrastructure perspective, these advantages include benefits that enhance reliability, improve efficiency, and prepare the utility for a sustainable energy future.⁵⁸

58. Staff's proposal is primarily a cost allocation and rate design proposal, and does not fully address the scope of terms and conditions required for a large load tariff. It

⁵³ Ex. 104, Gunn Surrebuttal, Page 9.

⁵⁴ Ex. 704, Wills Surrebuttal, Page 36.

⁵⁵ Ex. 704, Wills Surrebuttal, Pages 35-36.

⁵⁶ Ex. 704, Wills Surrebuttal, Page 36.

⁵⁷ Ex. 704, Wills Surrebuttal, Page 36.

⁵⁸ Ex. 551, Berry Surrebuttal, Pages 5-6.

also lacks cost of service models and the expert rate design analysis that a general rate case would provide.⁵⁹

59. Staff's proposal would not promote rate transparency or consistency, as it includes additional charges, such as the capacity shortfall rate, the capacity cost sufficiency rider, and the economic development discount responsibility rider.⁶⁰ These rate components include price levels dependent on volatile endogenous and exogenous variables beyond the LLPS customers' control, which increases the cost uncertainty the LLPS customer may be exposed to under the schedule. This uncertainty could brand Missouri as unattractive to LLPS customers, as additional charges and rate complexity does not equate to transparency for large load customers.⁶¹

60. Staff's proposal is not in-line with what other jurisdictions are adopting. Many of the conditions Staff recommends stray from the categories of terms and conditions that are emerging nationally for serving large loads, including: (1) extensive detailed load requirements where the large load customer defines its anticipated load by month and year for a minimum of 15 years, (2) demand measurement intervals, (3) time-based energy charges, and (4) termination fees.⁶²

61. Ratemaking in Missouri is based on a review of the utility's cost of providing service over a historical period as compared to its revenues over the same period, subject to certain normalizations, annualizations and other regulatory adjustments. The use of a historical test year results in regulatory lag.⁶³

⁵⁹ Ex. 551, Berry Surrebuttal, Page 10.

⁶⁰ Ex. 201, Staff Recommendation, Page 67.

⁶¹ Ex. 104, Gunn Surrebuttal, Page 17.

⁶² Ex. 104, Gunn Surrebuttal, Page 15.

⁶³ Ex. 704, Wills Surrebuttal, Page 38.

62. Regulatory lag can be positive for the utility resulting in increased revenues when there is customer growth between rate cases, resulting in revenues above those set in base rates. Conversely, regulatory lag can be negative for the utility in a rising cost environment when actual operating costs are above those set in base rates or when significant investment in plant is made between rate cases resulting in foregone depreciation and return on equity investment.⁶⁴

63. Evergy files quarterly surveillance reports that give Staff earnings information.⁶⁵

Conclusions of Law

A. Evergy is an “electrical corporation” and a “public utility” as defined in Sections 386.020(15) and 386.020(43), RSMo, respectively, and as such is subject to the personal jurisdiction, supervision, control and regulation of the Commission under Chapters 386 and 393 of the Missouri Revised Statutes.

B. Sections 393.130 and 393.140, RSMo, mandate that the Commission ensure that all utilities are providing safe and adequate service and that all rates set by the Commission are just and reasonable.

C. Section 393.130.7, RSMo, requires that regulated electrical corporations providing electric service to more than two hundred fifty thousand customers must develop and submit to the commission schedules (a tariff) applicable to customers who are reasonably projected to have above an annual peak demand of 100 MW or more.

⁶⁴ Ex. 704, Wills Surrebuttal, Pages 38-48.

⁶⁵ Ex. 104, Gunn Surrebuttal, Pages 6-7.

D. Section 393.130.7, RSMo, requires that each regulated electrical corporation providing electric service to two hundred fifty thousand or fewer customers as of January 1, 2025, shall develop and submit to the Commission such schedules applicable to customers who are reasonably projected to have above an annual peak demand of 50 MW or more.

E. Section 393.130.7, RSMo, states that the schedules should reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers.

F. The Commission may file an action “upon its own motion or upon complaint” if it suspects that the utility’s rates or charges are “unjust, unreasonable, unjustly discriminatory or unduly preferential or in any wise in violation of any provision of law.”⁶⁶

G. Pursuant to Commission Rule 20 CSR 4240-2.115(2)(D), a nonunanimous stipulation and agreement to which a timely objection has been filed becomes a position of the signatory parties. However, the Signatories are not bound by the position in the objected to nonunanimous stipulation and agreement and all issues remain for determination by the Commission.

H. Commission Rule 20 CSR 4240-2.115(2) provides that a party objecting to a nonunanimous stipulation and agreement must identify the specific provisions of the stipulation and agreement to which they are objecting.

⁶⁶ Section 393.140(5), RSMo.

I. Missouri regulated utilities are required to serve all persons within their service territory.⁶⁷

Decision

Every regulated utility in Missouri, including Evergy, has an obligation to serve any customer who requests service within their territory (with few exceptions). This case asks the Commission to decide how Evergy should serve customers anticipated to consume large amounts of energy, consistent with recently enacted state law encouraging economic development while protecting existing customers.

Evergy's original LLPS Rate Plan, contained in its Application, was modified by the Agreement filed a few days before the evidentiary hearing was set to begin. Staff put forth its own proposal to counter the proposal in Evergy's Application.

The Agreement requests approval of Evergy's proposed comprehensive LLPS Rate Plan, as amended by the terms of the Agreement, including a new Schedule LLPS, together with related riders and tariff modifications, and asks the Commission to find the package reasonable and in the public interest. The LLPS Rate Plan, as amended by the Agreement, applies to new facilities or expansions at a monthly maximum demand of 75 MW.

The proposed Agreement was signed by 7 out of 10 participants in the case. Those Signatories represent the interests of large load customers such as Google, Velvet, and DCC; environmental interests such as Sierra Club and Renew Missouri; as well as utility

⁶⁷ "The certificate of convenience and necessity issued to the utility is a mandate to serve the area covered and it is the utility's duty, within reasonable limitations, to serve all persons in an area it has undertaken to serve." *State v. Public Service Commission*, 343 S.W.2d 177, 181 (Mo.App.1960).

interests such as Evergy and Ameren. The Signatories to the Agreement represent a diverse and extensive group of stakeholders who support the LLPS plan. The Signatories assert that Evergy's original LLPS Rate Plan, as modified by the Agreement, establishes reasonable protections and safeguards for Evergy's existing customers while ensuring that LLPS customers pay their appropriate share of system costs required to serve new large loads as well as providing a competitive rate program which will benefit all Missourians. For the reasons set out in more detail below, the Commission finds that the record supports this assertion.

Because the Agreement reflects emerging trends in LLPS tariffs being implemented in other jurisdictions, approving it will put Missouri on a level playing field with other states in seeking to attract large load customers and the economic benefits they bring. Also consistent with emerging trends, the Agreement includes protections for other ratepayers and provisions that require those large load customers to pay their respective share of incremental costs.⁶⁸

Evergy's LLPS Rate Plan proposal, as modified by the Agreement, is the best resolution of this case because it implements a complete LLPS framework that aligns with Section 393.130.7, RSMo, by establishing a tariffed service and class for customers at or above 75 MW of demand, with clear eligibility, pricing, commitments, and safeguards that ensures these customers pay their share of costs while enabling Missouri to compete for transformational loads.

⁶⁸ Section 393.130.7, RSMo, states that the schedules should reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers.

The Agreement balances flexibility through customer-specific LLPS Service Agreements. The Agreement reduces stranded cost risks and protects other customers from bearing the unanticipated consequences of an LLPS customer's load leaving before the end of their contract term.

The Agreement contains built in protections. The Minimum Monthly Bill includes a Demand component with the minimum demand set at 80 percent of Contract Capacity; a Customer Charge; a Grid Charge defined by measured grid demand; a Reactive Demand Adjustment; and other demand-based riders. It adds a Cost Stabilization Rider, designed to ensure recovery of costs incurred to serve LLPS customers, calculated annually and made non-bypassable relative to any Economic Development Rider discount so that LLPS customers cover the costs they impose. These features will make the LLPS class self-sustaining.

To guard against credit risk, the Agreement requires collateral equal to two years of Minimum Monthly Bills, with exemptions tiered to credit ratings and liquidity, quarterly re-computation, and clear forms of acceptable security, including guarantees and letters of credit with specific draw rights upon breach.

As with emerging tariffs being proposed in other jurisdictions, the Agreement provides large load customers options to achieve their clean energy and infrastructure goals. It incorporates four new optional clean and renewable energy riders that would be available to qualifying LLPS customers and allow them to participate in specific programs, the cost of which would be borne by the participating LLPS customer and/or Evergy. This would enable large customers, including data centers, to meet sustainability goals without shifting costs to others.

The Commission finds that Evergy's LLPS Rate Plan as modified by the Agreement, which is backed by a broad coalition - spanning utilities, industrial customers, technology companies, and environmental organizations - satisfies the requirements of Section 393.130.7, RSMo.

The Commission is not persuaded by Staff's assertion that the Agreement should be rejected in favor of Staff's proposal. Testimony in the hearing showed that Staff's proposal was developed without the benefit of an engagement process with large load customers or utilities or stakeholders, or a thorough analysis of comparable tariffs from other jurisdictions. Staff's proposal is fundamentally different from emerging industry standards for LLPS tariffs in that it is primarily a cost allocation and rate design proposal and fails to adequately address the full scope of terms and conditions required for a large load tariff. Under Staff's proposed framework, large load customers would face charges disconnected from actual costs and would be denied any viable pathway to achieving their clean energy goals. Additionally, Staff's proposed rate structure and requirement that each large load customer be served by a separate commercial pricing node would add significant administrative burdens to track very minor categories of cost.

Staff's proposed one-way revenue tracker is also unreasonable. It would require Evergy to absorb any cost increases associated with large load service while a hundred percent of the revenues resulting from that service would be deferred in a one-way tracker for future return to customers. Such a proposal is inconsistent with balancing all parties' interests.

Staff's proposal is also unreasonably complex and would both increase rate uncertainty and diminish incentives for large load customers to locate and invest in

Missouri. Staff's proposed rate structure includes distinct pricing for 25 rate elements, and many of those rate elements depend on tracking deviations to execute the billing. Staff's proposal also includes additional charges, which include price levels dependent on volatile endogenous and exogenous variables beyond the LLPS customers' control, which would further increase LLPS customer cost uncertainty. Under Staff's proposal, neither a prospective large load customer nor Evergy on the customer's behalf could confidently model the expected rate to inform their site selection efforts, which could drive away large load customers from the state and deprive ratepayers of the advantages such customers can provide.

The Commission finds that Evergy's LLPS Rate Plan, as amended by the Agreement, offers the best resolution for providing service to LLPS customers and satisfies the requirements of Section 393.130.7, RSMo. It resolves issues related to serving LLPS customers, reflects broad stakeholder consensus, sets the framework for an LLPS rate schedule, and contains strong safeguards to ensure that large new loads pay their fair share while enabling growth that benefits Missouri. It offers a comprehensive, workable framework that gives Missouri a competitive LLPS program while embedding firm protections for existing customers.

Issues not addressed in the Agreement

Issue C - Should any limit be placed on Evergy concerning the amount of LLPS load that it may serve?

Findings of Fact

64. Staff proposed a restriction that only up to 33 percent of the annual Missouri jurisdictional load of the respective utility could be comprised of LLPS customers.⁶⁹

65. There is no specific justification for the 33 percent proposed by Staff, which is an arbitrary limit that could have many unintentional consequences, such as denying service to a large load customer with clear economic benefit to the state.⁷⁰

Conclusions of Law

J. There are no additional Conclusions of Law for this issue.

Decision

The Commission finds Staff's proposal to restrict the LLPS customer load to a set percentage of Evergy's Missouri jurisdictional load unreasonable. Further, Staff provided no analysis to support why any such limit should be set at 33 percent. The Commission will not order a limit on the load from LLPS customers.

Issue K - Are changes needed for the Emergency Energy Conservation Plan tariff sheet and related tariff sheets to accommodate LLPS customers?

Findings of Fact

66. Staff recommends the Emergency Energy Conservation Plan tariff sheets should indicate that customers taking service under Schedule LLPS may be interrupted during grid emergencies under the same circumstances as any other customer.⁷¹

67. OPC recommends service under the LLPS schedule be subject to mandatory emergency curtailments as warranted.⁷²

⁶⁹ Ex. 201, Staff Recommendation, Page 69.

⁷⁰ Ex. 105, Lutz Surrebuttal, Page 33.

⁷¹ Ex. 201, Staff Recommendation, Page 112.

⁷² Ex. 301, Marke Rebuttal, Page 25.

68. Both EMW and EMW have an Emergency Energy Conservation Plan in their respective General Rules and Regulation, which were aligned on January 1, 2025, and comply with the North American Electric Reliability Corporation Standard EOP-011-1. The plans define an emergency and highlight the major steps that will be taken during an emergency called the SPP Reliability Coordinator. Under the Emergency Energy Conservation Plan, LLPS customers are subject to curtailment unless they are deemed an essential service.⁷³

Conclusions of Law

K. There are no additional Conclusions of Law for this issue.

Decision

Both Staff and OPC recommended that Evergy's Emergency Energy Conservation Plan explicitly include LLPS customers for potential curtailment in different manners. LLPS customers, including data centers, provide different types of service, including to different types of customers, which will dictate on a case-by-case basis if they are classified as essential service. Evergy's Emergency Energy Conservation Plan outlines that LLPS customers are subject to curtailment unless deemed an essential service. Therefore, with an existing plan in place, the Commission does not see the need for modifications proposed by either Staff or OPC and the Commission rejects both Staff's and OPC's proposals.

Issue L - What studies should be required for customers to take service under the LLPS tariff?

Findings of Fact

⁷³ Ex. 105, Lutz Surrebuttal, Page 21.

69. Evergy's proposed studies are outlined in its "Path to Power", which outlines a process for load interconnection of large load customers. The "Path to Power" is a 5-phase process, which includes steps to assess if transmission upgrades are required along with reviews by SPP.⁷⁴

70. According to Evergy, new large load projects are evaluated and negotiated in groups to help Evergy and SPP better understand the broader system implications of new large customer load. Evergy gathers all necessary information to submit the project to SPP for an Area Qualification (AQ) study consistent with SPP's standard process, and as part of Evergy's "Path to Power" process. The AQ study determines if new load can be reliably connected to the grid and identifies any potential transmission upgrades that may be needed to reliably interconnect the facility.⁷⁵

71. Staff proposed that Evergy should conduct studies as contemplated by its proposed Path to Power approach, including any requirements under its Transmission Facility Interconnection Requirements.⁷⁶

72. OPC recommends three studies, which are Total Harmonic Distortion, Power Usage Effectiveness and Water Usage Effectiveness.⁷⁷

73. The studies proposed by OPC have not been identified as part of Evergy's industry reviews and do not appear to be a normal component of utility large load processes.⁷⁸

⁷⁴ Ex. 102, Martin Direct, Pages 7-13.

⁷⁵ Ex. 102, Martin Direct, Pages 9-11.

⁷⁶ Ex. 205, Corrected Eubanks Surrebuttal, Page 5.

⁷⁷ Ex. 301, Marke Rebuttal, Pages 5-15.

⁷⁸ Ex. 104, Gunn Surrebuttal, Page 20.

74. Evergy's Interconnection Standards and its general oversight of power quality are the appropriate place to address the concern that would be covered by the Total Harmonic Distortion study.⁷⁹

75. Large load customers tend to have a high focus on efficiency concerns and Evergy has not noticed a need to become involved in their behind the meter activities related to energy efficiency and water conservation.⁸⁰

76. Meta reports that its Kansas City Data Center is LEED Gold certified, which means that this data center has achieved very high standards for energy efficiency, water conservation, supply chain responsibility and recycling. They also state, "We're also prioritizing water stewardship, incorporating a cooling technology that is significantly more water efficient than the industry standard."⁸¹

77. The parties in the Agreement agreed to reflect the framework of the Path to Power in Evergy's General Rules and Regulations.⁸²

Conclusions of Law

L. No additional Conclusions of Law are necessary for this issue.

Decision

Water conservation and energy efficiency are important factors for large load customers in meeting their sustainability goals and are key elements they manage behind the meter. To require every large load customer to perform a total harmonics study instead of addressing any concerns through Evergy's interconnection standards and

⁷⁹ Ex. 104, Gunn Surrebuttal, Pages 22-23.

⁸⁰ Ex. 104, Gunn Surrebuttal, Page 21.

⁸¹ Ex. 104, Gunn Surrebuttal, Page 21.

⁸² Non-Unanimous Global Stipulation and Agreement, Page 21.

oversight of power quality standards would make the process unduly onerous for large load customers, thereby creating barriers to entry into the Missouri market. The Commission does not find the evidence presented by OPC in support of these studies convincing and finds the studies would be duplicative of efforts already performed by large load customers and Evergy. The Commission rejects OPC's proposal for the Power Usage Effectiveness, Water Usage Effectiveness, and Total Harmonic Distortion studies.

Staff's proposal to perform the studies outlined in the "Path to Power" are already incorporated into the provisions of the Agreement.

The Commission will not order any additional studies.

Issue M - Should a form customer service agreement be included in the Commission approved LLPS tariffs resulting from this case?

Findings of Fact

78. Staff recommends the inclusion of a form service agreement in the tariff coupled with Commission approval, be applicable to any electric utility service large loads as defined in Section 393.130.7, RSMo.⁸³

79. Staff recommends that terms of service and rates for service be reflected in the promulgated tariff and not reserved to confidential agreements that are not subject to Commission review and might be subject to change at Evergy's discretion.⁸⁴

80. Due to a very diverse customer base, a form energy service agreement would not provide Evergy with the flexibility to deal with customers and their particular

⁸³ Ex. 205, Corrected Eubanks Surrebuttal, Page 3.

⁸⁴ Ex. 104, Gunn Surrebuttal, Page 8.

abilities and capabilities but would potentially hamper Evergy's ability to negotiate with these customers.⁸⁵

Conclusions of Law

M. There are no additional Conclusions of Law for this issue.

Decision

Staff asks the Commission to require Evergy to include a form LLPS service agreement in its tariff to serve LLPS customers. Large load customers are often highly individualized and not amenable to a one-size-fits all approach. A form service agreement would hamper Evergy's ability to exercise reasonable discretion in the service to its large load customers.

The Commission will not require Evergy to include a form LLPS service agreement in its tariff.

Issue N - Should Evergy be required to disclose information about prospective customers?

- a. If so, what review should the Commission have of prospective customers and terms applicable to specific customers?
- b. In what case should said review occur?

Findings of Fact

81. To help track the uptake and success of the LLPS Rate Plan, Evergy stated it will provide the Commission with an annual report - either in this docket or through a repository docket - that will include the number of new or expanded customers that have enrolled in Schedule LLPS; the total estimated load enrolled under each rate; the sector

⁸⁵ Transcript Vol. II, Page 150.

the customer is in; and the estimated number of new or retained jobs associated with each new customer (to the extent available).⁸⁶

82. Because large load customers often consider their energy usage information to be proprietary and commercially sensitive information, Evergy proposes to provide these updates on an anonymized basis.⁸⁷

83. Staff asked the Commission to require Evergy, and every other regulated electric utility in Missouri, to provide actual potential customer lists to the Commission and anticipated loads for each customer on a quarterly basis.⁸⁸

84. Staff indicated this customer specific information is needed for the following four reasons:

- a. To ensure that the claims that are being made by the utility are correct;
- b. To be able to compare utilities within the state to ensure that multiple Missouri utilities are not counting the same potential customer;
- c. To be able to evaluate the magnitude, location, and timing of energy usage impacts to fuel and purchased power costs as well as the planning of transmission and distribution facilities; and
- d. To be able to review the overall load characteristics of a potential large load customer.⁸⁹

Conclusions of Law

N. There are no additional Conclusions of Law for this issue.

⁸⁶ Ex. 100, Gunn Direct, Page 25.

⁸⁷ Ex. 100, Gunn Direct, Page 25.

⁸⁸ Ex. 200, Busch Rebuttal, Page 13.

⁸⁹ Ex. 200, Busch Rebuttal, Pages 13-15.

Decision

Staff did not provide a convincing argument as to why such proprietary and commercially sensitive information is needed prior to a utility executing an LLPS Service Agreement with a prospective customer. The Commission will not order Evergy to disclose information on its prospective customers.

Issue O - Should LLPS customers be included in the FAC?

- a. What, if any, changes should be made to Evergy's existing FAC tariff sheet?**
- b. When/in what case should these changes be made?**
- c. What if any FAC related costs should the Commission order tracked?**

Findings of Fact

85. When a new LLPS customer comes onto the system it will begin paying for every kWh of energy it consumes. The energy rates under current consideration range from \$0.02988 per kWh under Evergy's requested EMM rate, and \$0.0288 per kWh under Evergy's requested EMW rate, to Staff's around-the-clock average EMM rate of \$0.0270 per kWh and \$0.0269 per kWh for EMW, with specific rates depending on the time period in which energy is consumed.⁹⁰

86. Simultaneously, EMM and EMW will reflect additional energy costs in their respective utilities' FAC. While required Federal Energy Regulatory Commission (FERC) netting may result in this additional load appearing as an increase to expense or as a decrease to revenue in any given accumulation period filing, the reality is that the simple act of selling more energy to retail customers results in EMM or EMW transacting more

⁹⁰ Ex. 201, Staff Recommendation, Page 64.

energy purchases through the FAC. This is applicable to the Day Ahead market, the Real Time market, the ancillary services market, and for various SPP schedules which are assessed to EMM and EMW based on metrics like the load-ratio share, or various measures of demand.⁹¹

87. Staff acknowledges a reverse effect as well if a LLPS customer leaves the system and reduces Evergy's load after that customer has been recognized in base rates and the FAC base factor. Evergy would then no longer incur the wholesale energy and transmission expense associated with service to that customer. In this case, it would be reasonable to make an adjustment so that other customers do not unreasonably benefit from the significant reduction in wholesale energy expense that results. This is a mechanism similar to the "N Factor" that was utilized in the Ameren Missouri FAC associated with its service to Noranda.⁹²

88. It is Staff's understanding that FAC tariff sheets cannot be changed outside of a general rate case. Therefore, Staff recommends that the FAC LLPS adjustments be incorporated in the FAC tariff sheet and agreed to by the parties to take place in the next general rate case(s). Until then, however, the LLPS adjustments should be tracked and recorded as a regulatory asset or liability until the next rate case(s).⁹³

89. Staff recommends the following treatment of LLPS customer revenues:

- a. Until a rate case recognizing the customer at the full level of projected demand, the difference between the revenue for each charge considered for that customer in the last general rate case, and the

⁹¹ Ex. 201, Staff Recommendation, Page 64.

⁹² Ex. 201, Staff Recommendation, Pages 65-66.

⁹³ Ex. 201, Staff Recommendation, Page 66.

current level of revenue for that charge will be recorded to a regulatory liability account. This treatment is applicable to revenue from all charges except the Customer Charge, Facilities Charge, Demand Deviation Charge, Imbalance Charge, Capacity Shortfall Rate, the Capacity Cost Sufficiency Rider, and the RES Compliance Charge. The resulting regulatory liability will be treated as an offset to production rate base with a 50-year amortization. The annualized and normalized revenue from these charges shall be reflected in each rate case.

- b. All revenue billed under the RES Compliance charge will be recorded to a regulatory liability, and that regulatory liability will be treated as an offset to production rate base with a 50-year amortization. Revenue for the RES Compliance charge will only be addressed through this accumulated regulatory liability and shall not be considered as rate revenue in rate cases.
- c. All revenue billed under the Demand Deviation Charge, Imbalance Charge, Capacity Shortfall Rate, and the Capacity Cost Sufficiency Rider will be used to offset expense associated with the increased cost of service caused by the LLPS customer in any applicable rate case or through the FAC, if applicable.
- d. Unless the FAC is modified to address positive regulatory lag associated with LLPS customer growth, the difference caused by positive customer growth between normalized and actual LLPS Day Ahead Energy Charge revenues shall be recorded to a regulatory liability. The resulting

regulatory liability will be treated as an offset to production rate base with a 50-year amortization. The annualized and normalized revenue from these charges shall be reflected in each rate case.⁹⁴

90. Under Evergy's-recommended LLPS tariff, Evergy determined the FAC tariff could be used without changes. FAC changes would only be needed to address renewable program additions.⁹⁵

91. There are concerns with the large number of new charges that could directly or indirectly impact the FAC under the Staff-recommended LLPS tariff. Most of the concerns are raised in response to the proposed use of commercial pricing nodes, something not currently common at the SPP. These concerns include the list of alternate data Staff believes is necessary if the commercial pricing node recommendation is not accepted.⁹⁶

92. The list of alternate data is based entirely on Staff's opinion and has not been vetted to determine if the data should be provided or even if the data can be provided. The full impact of the Staff-proposed approaches has not been reconciled to the level required to effectuate the FAC.⁹⁷

93. The SPP Market Working Group rejected a proposal for separate commercial pricing nodes for Conditional High Impact Large Load ("CHILL") customers at a meeting in September 2025.⁹⁸

⁹⁴ Ex. 201, Staff Recommendation, Page 67, "Treatment of LLPS Customer Revenues" table.

⁹⁵ Ex.105, Lutz Surrebuttal, Page 33.

⁹⁶ Ex. 105, Lutz Surrebuttal, Pages 33-34

⁹⁷ Ex. 105, Lutz Surrebuttal, Page 34.

⁹⁸ Transcript Vol. II, Pages 192, 194.

94. Regionally, SPP is seeking approval of Revision Request 696 – Integrate and Operate High Impact Large Loads from its Board and FERC. Revision Request 696 includes several elements related to the process of interconnection and study. Additionally, it creates a path for conditional service through a proposed solution referred to as CHILL, “with the trade-off of potential temporary curtailments, in exchange for quick and thorough study results that allow them to integrate and operate as quickly as possible.”⁹⁹

95. OPC proposed to split the FAC into two; one for non-LLPS customers and the second for LLPS customers.¹⁰⁰

Conclusions of Law

O. Section 386.266(5), RSMo, provides that the Commission shall have the power to approve, modify, or reject adjustment mechanisms, such as the FAC, only after providing the opportunity for a full hearing in a general rate proceeding.

Decision

Staff proposes tracking FAC costs of LLPS customers so they can be recorded as a regulatory asset or liability included in a rate case. FAC cost separation could occur if LLPS customers are registered as a separate pricing node, but SPP voted down such a process for CHILL customers.

OPC proposed to modify Everygy current FAC by splitting it into LLPS and non-LLPS customers. OPC argues that non-LLPS customers will pay the costs of LLPS customers through the FAC and non-LLPS customers should subsidize LLPS costs. As

⁹⁹ Ex. 201, Staff Recommendation, Page 112.

¹⁰⁰ Ex. 300, Mantle Surrebuttal, Page 3.

previously concluded, the Commission cannot do as OPC proposes as it cannot modify Evergy's current FAC outside of a general rate proceeding.

The Commission will not change the existing FAC tariff sheet until a rate case is filed.

Issue P - Should LLPS customers be registered with a separate Southwest Power Pool ("SPP") commercial pricing node (subject to SPP support) or alternatively should Evergy be required to provide the Staff-recommended data (Appendix 2, Schedule 2) node?

Findings of Fact

96. Separate commercial pricing nodes would require the utility to allocate its resource stack on a nodal, rather than system basis. This would require the utility to decide which generation asset would be assigned to each node, which increases concerns of cross-subsidization and transparency, contrary to Section 393.130.7.¹⁰¹

97. There are a multitude of issues with the disaggregation of commercial pricing nodes. The settlement process would forego the single, unified energy charge and would require separate accounting for fuel procurement expense, uplift charges, and congestion-management costs.¹⁰²

98. Disaggregation magnifies forecasting errors. Under an aggregated model, any over or under-estimation at a specific node is statistically decreased by the diversity of the broader portfolio.¹⁰³

¹⁰¹ Ex. 103, Brown Surrebuttal, Page 11.

¹⁰² Ex. 103, Brown Surrebuttal, Page 10.

¹⁰³ Ex. 103, Brown Surrebuttal, Page 10.

99. Once the portfolio is separated into discrete, high-volume nodes, that diversity benefit of an aggregated model is lessened, and forecasting inaccuracies accumulate, thereby increasing volatility in settlement results.¹⁰⁴

Conclusions of Law

P. The Federal Power Act (FPA), 41 Stat. 1063, as amended, 16 U.S.C. Section 791a et seq., authorizes the FERC to superintend the sale of electricity in interstate commerce.¹⁰⁵

Q. The FPA gives FERC authority to regulate "the sale of electric energy at wholesale in intrastate commerce."¹⁰⁶

Decision

The SPP's aggregate utility load does not have customer-by-customer node registration and there is no provision for discrete pricing nodes for retail customers. To have each large load customer registered at a commercial pricing node would require disaggregation of commercial pricing node information, which would result in significantly more work for the utility and lead to significant accuracy issues. The SPP Market Working Group rejected separate commercial pricing nodes for CHILL customers.

Ultimately, SPP determines where nodes are located throughout its footprint. Its treatment of where it places nodes should be consistent throughout the footprint.

The Commission will not require LLPS customers to have a commercial pricing node nor will they require Evergy to provide data on that node.

¹⁰⁴ Ex. 103, Brown Surrebuttal, Page 10.

¹⁰⁵ *NRG Power Marketing, LLC, v. Main Public Utilities Commission*, 558 U.S. 165, 169 (2010).

¹⁰⁶ 16 U.S.C. Section 824(b)(1), See also, *NRG Power Marketing, LLC, v. Main Public Utilities Commission*, 558 U.S. 165, 171 (2010).

Issue R - What treatment is needed to address revenues from LLPS customers occurring between general rate cases?

Findings of Fact

100. If dollars from existing customers were collected through a construction work in progress (CWIP) accounting those dollars could be directly offset by revenues collected from any LLPS customers receiving service .¹⁰⁷

101. Staff's proposal would require Evergy to track revenues associated with a large load customer after it came online between rate cases. The proposal is two pronged. It is intended to deal with positive regulatory lag, and it's also intended to be a direct offset to additional rate base.¹⁰⁸

102. Evergy's recent general rate case before the Kansas Corporation Commission included an earnings-sharing mechanism to address revenues between rate cases. The Commission here would have the authority to approve a similar mechanism in a future rate case after LLPS customers begin receiving service in Missouri.¹⁰⁹

103. The earnings-sharing mechanism proposed in Kansas assumed Evergy was earning its authorized rate of return.¹¹⁰

Conclusions of Law

R. The ability to use a deferral mechanism is a policy decision within the Commission's discretion, the Commission has generally followed the guidance in the

¹⁰⁷ Transcript Vol III, Pages 56-57.

¹⁰⁸ Transcript, Vol III, Page 57.

¹⁰⁹ Transcript Vol. II, Pages 151-152.

¹¹⁰ Transcript Vol. II, Pages 151-152.

Uniform System of Accounts (USOA) that costs should not be deferred to another accounting period except for “extraordinary items.”¹¹¹

S. The Commission has authority to defer extraordinary costs of a utility for consideration in a later period. In doing so, it is not engaging in single-issue rate making.¹¹²

T. An AAO permits “extraordinary items” to be deferred and accounted for in a future accounting period.¹¹³

Decision

There are no current LLPS customers and no rate base being collected through CWIP accounting from existing customers. Thus, there are no known and measurable revenues, or a quantification of how those revenues could be a direct offset to additional rate base constructed to meet the energy needs of LLPS customers that might be recovered from existing customers before a rate case. Staff’s reasoning that revenues resulting from positive regulatory lag would be used to offset the implementation of a mechanism to reduce negative regulatory lag is only hypothetical at this point in time. In other words, it is premature for the Commission to establish a regulatory mechanism at this time to capture dollars that do not currently exist. Any treatment of revenues from LLPS customers will be determined in a future rate case where those revenues would be known and measurable.

Issue U - Should the Commission order a community benefits program as described in the testimony of Dr. Geoff Marke?

¹¹¹ *Kan. City Power v. Public Serv. Comm*, 509 S.W.3d 757 at 770 (Mo.App. W.D. 2016).

¹¹² *State ex rel. Office of Pub. Counsel v. Pub. Serv. Com’n of Mo.*, 858 S.W. 2d 806 (Mo. App. W.D. 1993).

¹¹³ See *State ex rel. Aquila, Inc. v. Pub. Serv. Comm’n*, 326 S.W.3d 20, 27 (Mo. App. W.D. 2010).

Findings of Fact

104. OPC's recommendation to include a community benefits program to counterbalance the subsidization of LLPS customers by non-LLPS customers is not found in other states.¹¹⁴

105. OPC witness Dr. Marke points to reductions in funding for Low Income Home Energy Assistance Program, Low-Income Weatherization Assistance Program, and the City of Kansas City's Urban Heat Island Mitigation initiative as the primary needs to be addressed by the program. It is uncommon that customer funding is used to support these governmental initiatives.¹¹⁵

Conclusions of Law

U. There are no additional Conclusions of Law for this issue.

Decision

OPC posits that the societal transition caused by LLPS customers, specifically data centers, will impact federally funded programs like the Low Income Home Energy Assistance Program (LIHEAP), the Low Income Weatherization Assistance Program (LIWAP) and the City of Kansas City's Urban Heat Island mitigation program. There is no evidence presented showing the inclusion of data centers and large load customers will create a societal transition. In addition, OPC provided no authority for the Commission to require one customer class to fund any program for another customer class.

The Commission will not order implementation of a community benefits program.

¹¹⁴ Ex. 105, Lutz Surrebuttal, Page 23.

¹¹⁵ Ex. 105, Lutz Surrebuttal, Page 23.

Closing

In making this decision, the Commission has considered the positions and arguments of all of the parties. After applying the facts to the law to reach its conclusions, the Commission concludes that the substantial and competent evidence in the record supports the conclusion that Evergy has met, by a preponderance of the evidence, its burden of proof to demonstrate that its LLPS Rate Plan as modified by the Agreement will produce schedules compliant with the requirements of Section 393.130.7, RSMo, and is the appropriate resolution of the majority of the issues in this case. Therefore, the Commission authorizes Evergy to file a LLPS tariff consistent with the terms of its LLPS Rate Plan, as modified by the Agreement, and the findings and determinations of this order.

THE COMMISSION ORDERS THAT:

1. Evergy is authorized to file LLPS schedules consistent with the LLPS Rate Plan filed with its Application, as modified by the terms of the Agreement, and the findings and determinations of this order.
2. This Report and Order shall become effective on December 13, 2025.

BY THE COMMISSION



A handwritten signature in black ink that reads "Nancy Dippell".

Nancy Dippell
Secretary

Hahn, Ch., Coleman, Kolkmeier,
and Mitchell CC., concur and certify compliance
with the provisions of Section 536.080, RSMo (2016).

Walker, Regulatory Law Judge

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 13th day of November 2025.



Nancy Dippell

Nancy Dippell
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

November 13, 2025

File/Case No. EO-2025-0154

**MO PSC Staff
Staff Counsel Department
200 Madison Street, Suite 800
P.O. Box 360
Jefferson City, MO 65102
staffcounsel@psc.mo.gov**

**Office of the Public Counsel (OPC)
Marc Poston
200 Madison Street, Suite 650
P.O. Box 2230
Jefferson City, MO 65102
opc@opc.mo.gov**

**Data Center Coalition
Alissa Greenwald
1580 Lincoln Street, Suite 1105
Denver, CO 80203
agreenwald@keyesfox.com**

**Data Center Coalition
Nikhil Vijaykar
4457 Howe St.
Oakland, CA 94611
nvijaykar@keyesfox.com**

**Evergy Missouri Metro
Cole Bailey
1200 Main St
Kansas City, MO 64105
cole.bailey@evergy.com**

**Evergy Missouri Metro
James Fischer
2081 Honeysuckle Lane
Jefferson City, MO 65109
jfischerpc@aol.com**

**Evergy Missouri Metro
Chandler Hiatt
4520 Main St #1100
Kansas City, MO 64111
chandler.hiatt@dentons.com**

**Evergy Missouri Metro
Roger Steiner
1200 Main Street, 16th Floor
P.O. Box 418679
Kansas City, MO 64105-9679
roger.steiner@evergy.com**

**Evergy Missouri Metro
Jacqueline Whipple
4520 Main Street, Ste. 1100
Kansas City, MO 64111
jacqueline.whipple@dentons.com**

**Evergy Missouri Metro
Karl Zobrist
4520 Main Street, Suite 1100
Kansas City, MO 64111
karl.zobrist@dentons.com**

**Evergy Missouri West
James Fischer
2081 Honeysuckle Lane
Jefferson City, MO 65109
jfischerpc@aol.com**

**Evergy Missouri West
Chandler Hiatt
4520 Main St #1100
Kansas City, MO 64111
chandler.hiatt@dentons.com**

**Evergy Missouri West
Roger Steiner
1200 Main Street, 16th Floor
P.O. Box 418679
Kansas City, MO 64105-9679
roger.steiner@evergy.com**

**Evergy Missouri West
Jacqueline Whipple
4520 Main Street, Ste. 1100
Kansas City, MO 64111
jacqueline.whipple@dentons.com**

**Evergy Missouri West
Karl Zobrist
4520 Main Street, Suite 1100
Kansas City, MO 64111
karl.zobrist@dentons.com**

**Google LLC
Frank Caro
900 W. 48th Place, Suite 900
Kansas City, MO 64112
fcaro@polsinelli.com**

**Google LLC
Jared Jevons
900 W. 48th Place, Suite 900
Kansas City, MO 64112
jjevons@polsinelli.com**

**Google LLC
Sean Pluta
7676 Forsyth Blvd
Suite 800
St. Louis, MO 63105
spluta@polsinelli.com**

**Google LLC
Andrew Schulte
900 W. 48th Place, Suite 900
Kansas City, MO 64112-6411
aschulte@polsinelli.com**

**Liberty (Empire)
Diana Carter
428 E. Capitol Avenue, Suite 303
Jefferson City, MO 65101
diana.carter@libertyutilities.com**

**Liberty (Empire)
Jermaine Grubbs
601 S. Joplin Ave.
Joplin, MO 64801
jermaine.grubbs@libertyutilities.com**

MO PSC Staff
Lexi Klaus
200 Madison Street
Jefferson City, MO 65101
lexi.klaus@psc.mo.gov

Nucor Steel Sedalia, LLC
Marc Ellinger
308 E. High Street, Ste. 300
Jefferson City, MO 65101
mellinger@ellingerlaw.com

Renew Missouri
Nicole Mers
501 Fay Street
Suite 206
Columbia, MO 65101
nicole@renewmo.org

Sierra Club
Bruce Morrison
4625 Lindell Blvd.
Suites 200 and 300
Saint Louis, MO 63108
bamorrison@greatriverslaw.org

Sierra Club
Sarah Rubenstein
319 N. 4th Street, Suite 800
St. Louis, MO 63102
srubenstein@greatriverslaw.org

Sierra Club
Caitlin Stiltner
4625 Lindell Blvd
Suites 200 & 300
St. Louis, MO 63108
cstiltner@greatriverslaw.org

Union Electric Company
Paula Johnson
1901 Chouteau Avenue
St Louis, MO 63103
amerenmoservice@ameren.com

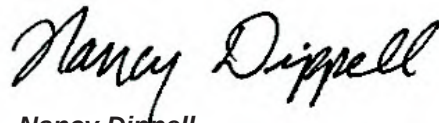
Union Electric Company
James Lowery
9020 S. Barry Road
Columbia, MO 65203
lowery@jblawllc.com

Union Electric Company
Wendy Tatro
1901 Chouteau Ave
St. Louis, MO 63103-6149
amerenmoservice@ameren.com

Velvet Tech Services, LLC
Stephanie Bell
308 East High Street, Suite 300
Jefferson City, MO 65101
sbell@ellingerlaw.com

Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,



Nancy Dippell
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.

EXHIBIT C

1 Diversified Reporting Services, Inc.

2 RPTS EUELL

3 HIF202000

4

5

6 MARKUP OF:

7 H.R. 9340, RATEPAYER PROTECTION ACT;

8 H.R. 9332, LOAD FORECASTING ENHANCEMENT ACT

9 H.R. 9339, AFFORDABLE INNOVATION FOR THE GRID ACT;

10 H.R. 9335, ADVANCED TRANSMISSION TECHNOLOGY TO REDUCE RATES
11 ACT;

12 H.R. 6633, HIGH-CAPACITY GRID ACT;

13 H.R. 6529, PROTECTING FAMILIES FROM AI DATA CENTER ENERGY
14 COSTS ACT;

15 H.R. 9338, PIPELINE SAFETY AUTHORIZATION ACT OF 2026;

16 H.R. 9617, COORDINATING AND HARNESSING AMERICA'S RECOVERY OF
17 MINERALS (CHARM) ACT;

18 H.R. 9616, ENVIRONMENTAL MONITORING AND REMEDIATION
19 TECHNOLOGY ASSESSMENT INITIATIVE (EMRTAI) ACT OF 2026;

20 H.R. 1266, COMBATING ILLICIT XYLAZINE ACT;

21 H.R. 2004, TYLER'S LAW;

22 H.R. 7970, STOP NITAZENES ACT;

23 H.R. 1561, ALERT COMMUNITIES ACT;

24 H.R. 7994, HERO ACT;

25 H.R. 8005, STOP PILLS THAT KILL ACT;

26 H.R. 7184, PRESS ACT;

27 H.R. 5880, FIGHT ILLICIT PILL PRESSES ACT;

28 H.R. 9393, LOWER COSTS, MORE TRANSPARENCY ACT OF 2026;
29 H.R. 9390, PRICES ON THE WALL ACT OF 2026;
30 H.R. 9397, PREMIUM TRANSPARENCY ACT;
31 H.R. 9396, PRIOR AUTHORIZATION ACCOUNTABILITY ACT;
32 H.R. 3514, IMPROVING SENIORS' TIMELY ACCESS TO CARE ACT OF
33 2025;
34 H.R. 9392, MEDICARE ADVANTAGE COST TRANSPARENCY ACT;
35 H.R. 5243, TO AMEND TITLE XVIII OF THE SOCIAL SECURITY ACT TO
36 INCREASE DATA TRANSPARENCY FOR SUPPLEMENTAL BENEFITS UNDER
37 MEDICARE ADVANTAGE;
38 H.R. 9389, _ NUTRITION EDUCATION AND CHRONIC DISEASE
39 PREVENTION IN COMMUNITY HEALTH CENTERS ACT OF 2026;
40 H.R. 8201, EXPANDING COMMUNITY ACCESS TO HEALTH SERVICES ACT;
41 H.R. 5526, BIOSIMILAR RED TAPE ELIMINATION ACT;
42 H.R. 8908, STOP GAMES ACT OF 2026; AND
43 H.R. 9661, EXPEDITED ACCESS TO BIOSIMILARS ACT
44 TUESDAY, JULY 21, 2026
45 House of Representatives,
46 Committee on Energy and Commerce,
47 Washington, D.C.

48 The committee met, pursuant to call, at 10:00 a.m. in
49 Room 2123, Rayburn House Office Building, Hon. Brett Guthrie
50 [chair of the committee] presiding.

51 Present: Representatives Guthrie, Latta, Griffith,
52 Bilirakis, Hudson, Carter of Georgia, Palmer, Crenshaw,

53 Joyce, Weber, Allen, Balderson, Fulcher, Pfluger,
54 Harshbarger, Miller-Meeks, Cammack, Obernolte, James, Bentz,
55 Houchin, Fry, Lee, Langworthy, Kean, Rulli, Evans, Goldman,
56 Fedorchak; Pallone, DeGette, Schakowsky, Matsui, Castor,
57 Tonko, Clarke, Ruiz, Peters, Dingell, Veasey, Kelly,
58 Barragan, Soto, Schrier, Trahan, Fletcher, Ocasio-Cortez,
59 Auchincloss, Carter of Louisiana, Menendez, Mullin, Landsman,
60 and McClellan.

61 Staff Present: Ansley Boylan, Director of Operations;
62 Byron Brown, Chief Counsel; Jessica Donlon, General Counsel;
63 Michael Essington, Chief Counsel; Andrew Furman, Professional
64 Staff Member; Calvin Huggins, Clerk; Megan Jackson, Staff
65 Director; Noah Jackson, Clerk; AT Johnson, Special Advisor;
66 Brayden Lacefield, Special Assistant; Giulia Leganski, Chief
67 Counsel; Mary Martin, Chief Counsel; Madeline Martinez, Staff
68 Assistant; Joel Miller, Chief Counsel; Ben Mullany, Press
69 Secretary; Ryan Murphy, Director of Member Services; Lillian
70 Noland, Clerk; Brice Ogle, Special Assistant; Clare Paoletta,
71 Professional Staff Member; Claire Richey, Clerk; Seth
72 Ricketts, Clerk; Jackson Rudden, Clerk; Chris Sarley, Member
73 Services/Stakeholder Director; Emma Schultheis, Professional
74 Staff Member; Arthur Speck, Professional Staff Member; Peter
75 Spencer, Senior Professional Staff Member; Dray Thorne,
76 Director of Information Technology; Timothy Trimble, Staff
77 Assistant; Matt VanHyfte, Communications Director; Katie

78 West, Press Secretary; Nick Wooldridge, Professional Staff
79 Member; Lydia Abma, Minority Policy Analyst; Jordan Antwi,
80 Minority Intern; Jennifer Black, Minority Professional Staff
81 Member; Ruth Campos, Minority Intern; Keegan Cardman,
82 Minority Staff Assistant; Timia Crisp, Minority Professional
83 Staff Member; Waverly Gordon, Minority Deputy Staff Director
84 and General Counsel; Tiffany Guarascio, Minority Staff
85 Director; Anthony Gutierrez, Minority Professional Staff
86 Member; Caitlin Haberman, Minority Staff Director, ENV; Perry
87 Hamilton, Minority Deputy Director, Member Services and
88 Outreach; Saha Khaterzai, Minority Professional Staff Member;
89 Alyssa Kimura, Minority Intern; Serena Klebba, Minority Staff
90 Assistant; Una Lee, Minority Chief Counsel, HE; Brendan
91 Lopez, Minority Press Assistant; Kristopher Pittard, Minority
92 Professional Staff Member; Emma Roehrig, Minority Staff
93 Assistant; Kylea Rogers, Minority Policy Analyst; Andrew
94 Souvall, Minority Director of Communications, Outreach, and
95 Member Services; Medha Surampudy, Minority Professional Staff
96 Member; Samantha Tate, Minority Intern; Hannah Treger,
97 Minority Staff Assistant; and Tuley Wright, Minority Staff
98 Director, ENG.

99 *The Chair. The committee will come to order, and we
100 will now resume the committee's markup.

101 We are considering several bills today, and I just want
102 to -- the kind of logistics of this -- we are considering

103 several bills, many bills, because of the hard work of so
104 many people on this committee to get us to this point. And
105 since we did miss a day we had scheduled but we figured it
106 would be hard to hold everybody here on the 4th of July break
107 so we are having to make that up here, so that does mean we
108 have a long day ahead of us. And so my hope is this, is that
109 I know there is some -- there will be amendments, and maybe
110 some bills we would all agree on. But if there is -- most of
111 the bills are agreed upon.

112 And so, when we call the roll -- obviously if you are in
113 the lounge or rooms off to the side and you miss your roll
114 and you come back into the room at the end. But once we get
115 to the bills that are -- everybody has agreed on is -- we
116 call the roll -- and make decisions. If you need to be
117 somewhere and say, I may miss that vote, that is -- I just
118 want to make sure we are going to be quick to call the roll
119 because, otherwise, we will never get through all the bills.

120 But if there is bills that -- I know everybody -- or
121 amendments, we will make sure we are flexible on that. So
122 that is kind of my intent, to get through the order we have
123 today. But we have so many bills today because so many
124 people have done so much hard work and have worked together,
125 and that is very, very much appreciated.

126 So the chair calls up H.R. 9340 and asks the clerk to
127 report.

128 *The Clerk. H.R. 9340, a bill to amend the Public
129 Utility Regulatory Policies Act of 1978.

130 *The Chair. Without objection, the first reading of the
131 bill is dispensed with, and the bill will be open for
132 amendment at any point.

133 So ordered.

134 [The bill follows:]

135

136 *****COMMITTEE INSERT*****

137

138 *The Chair. Does anyone seek to be recognized on the
139 bill?

140 The gentleman from Colorado is recognized for five
141 minutes to speak on the bill.

142 *Mr. Evans. Thank you, Mr. Chairman, and I also want to
143 thank Congresswoman Castor for co-leading the bill with me,
144 and today I speak in strong support of my bill, H.R. 9340,
145 the Ratepayer Protection Act, which does exactly what the
146 title suggests: protects everyday ratepayers from higher
147 electric bills due to unprecedented energy demand from data
148 centers.

149 This legislation codifies President Trump's Ratepayer
150 Protection Pledge which reinforces the public-private
151 commitment that data center developers in the U.S. pay for
152 the generation, transmission, and distribution that they
153 need. It is common sense, bipartisan, and it directly
154 responds to constituents' concerns about the cost of living
155 and potential financial burdens tied to rapid data center
156 development across the country.

157 Over the next decade demand for AI infrastructure will
158 continue to grow exponentially across the world. Large
159 amounts of computing power are required for daily operations
160 such as the everyday AI that you use on your cell phone.
161 Even more is needed for complex operations like research and
162 development for innovative technology and emerging industries

163 in places like aerospace or medical. These are industries
164 that employ thousands of Coloradans. We must ensure we are
165 building AI infrastructure responsibly, and we have policies
166 in place to reassure hard-working families that this new
167 development delivers benefits, not higher electric bills.

168 But at a time when radical climate mandates and blue
169 states like Colorado are reducing grid reliability and
170 passing down billions of dollars to ratepayers in favor of
171 portfolios that sometimes don't work, small businesses and
172 households need relief. We need more energy infrastructure
173 as soon as we possibly can so we can meet the demand. And
174 data centers are willing to cover the full cost of these
175 upgrades that they are triggering.

176 However, without a clear framework in place, states like
177 Colorado that lack a state standard for integrating large
178 data centers could pass on these additional costs to other
179 ratepayers, and monthly utility bills are going to spike.
180 And that is what the Ratepayer Protection Act addresses. It
181 specifically requires each state regulatory authority to
182 consider adopting a large load standard, one that applies to
183 data centers and hyperscalers with a demand of 100 megawatts
184 or more at a single facility, and it builds on three common
185 sense principles.

186 First, large data centers should cover the full
187 incremental cost of any generation, transmission, or

188 distribution upgrades needed to meet their high energy
189 demand. When a data center demand triggers the need for a
190 new high-voltage line or additional generation, they must
191 bear the costs, not small businesses or households in the
192 surrounding community.

193 Second, contracts should include meaningful financial
194 assurances upfront and long term to prevent overbuilding or
195 stranding assets that would otherwise leave everyday
196 consumers to absorb the cost. Communities should not be left
197 paying for infrastructure built around a single customer who
198 later scales back or relocates.

199 Third, states maintain authority to craft the specific
200 standards that suit their unique needs. This bill does not
201 impose a Federal mandate. Instead, it offers a thoughtful
202 Federal standard for states to consider as they evaluate how
203 best to integrate large loads. States understand their grids
204 and industries, and should engage with utilities, counties,
205 and local communities to choose the solution that works best
206 for them.

207 In my community and many others across the country,
208 people are anxious about the pace of data center development,
209 but they are terrified that Communist China will have control
210 over their information if we lose leadership in the AI space.
211 We are not opposed to innovation or economic opportunity; we
212 just want assurance that our monthly electric bills won't

213 skyrocket.

214 This bill advanced through the Energy Subcommittee on a
215 bipartisan basis because it is common sense. It keeps energy
216 costs low for Americans, it helps us build the energy
217 backbone required to compete and win in the AI era. A vote
218 for this bill is a vote for residential ratepayers. I urge
219 my colleagues on both sides of the aisle to support the
220 Ratepayer Protection Act.

221 And I yield back, Mr. Chairman.

222 *The Chair. The gentleman yields back. The gentlelady
223 from Florida --

224 *Ms. Schrier. This is the ANS?

225 *The Chair. No, this isn't the ANS, this is the bill.
226 He hasn't called the ANS. Do you want to speak on the ANS or
227 the bill?

228 Okay, the gentlelady from Washington is recognized for
229 five minutes to speak on the bill.

230 *Ms. Schrier. Thank you, Mr. Chairman.

231 Families in my district are struggling to get by, and my
232 constituents are bearing high costs on groceries and gas.
233 And for the last couple of years our utility bills have
234 skyrocketed. For many of my constituents, utility bills
235 jumped by almost 50 percent over the last 2 years. That jump
236 is caused by a few different factors, including the demand
237 from data centers moving in to buy our hydropower, which is

238 affordable. And as these hyperscalers continue to demand
239 more from our grid, we must implement guardrails that protect
240 our communities.

241 Data center companies, not ratepayers, should be
242 expected to pay for grid upgrades and energy. We should be
243 developing best practices now and not later for collecting
244 data to accurately forecast demand to prevent blackouts. And
245 as these companies continue to innovate, we need to
246 understand better how this new technology can make energy
247 more affordable to ensure that they do their part to improve
248 our lives. These bills are a good first step to do that, and
249 we should continue to use the levers of Congress to protect
250 our constituents. They benefit -- meaning big tech --
251 benefits from our data, from our power grid, and they
252 generate a whole lot of profit. And Congress must ensure
253 that our communities are benefiting from these promises of
254 innovation and not just getting stuck with the bill.

255 Thank you, and I yield back.

256 *The Chair. The gentlelady yields back. Is there any
257 on the Republican side to speak on the bill?

258 Seeing none, the gentlelady from Massachusetts is
259 recognized for five minutes to speak on the bill.

260 *Mrs. Trahan. Thank you, Mr. Chairman. I too support
261 the Ratepayer Protection Act and look forward to advancing
262 the bipartisan legislation to the House floor today.

263 Right now families across our country are afraid to open
264 up their electric bills. The number keeps climbing, and
265 their paycheck isn't keeping pace. They are doing the math
266 at the kitchen table, wondering what they might have to cut
267 next just to keep the lights on. That fear is real, and too
268 many families have stopped believing that anyone in
269 Washington is listening. They watch prices rise at the pump
270 and at the grocery store. They sit through weeks of brutal
271 heat and run the air conditioning that they can barely
272 afford. And now they read that a data center is coming to
273 their community, and they are told not to worry about what
274 that means for their bills.

275 Well, to be clear, data centers aren't going away. So
276 it is our job to make sure that when data centers are built
277 they are built on terms that work for the families who live
278 nearby. That is what this legislation gets right. It says
279 something simple: If you build the data center, you pay for
280 the data center, the construction costs, the utility costs.
281 Those fall on the company, not the family down the street.
282 This bill gives states a strong standard to make sure large
283 load developers foot the bill themselves. That is a real
284 move toward keeping these costs off our constituents' bills.

285 I am also glad H.R. 6529, the Protecting Families from
286 AI Data Energy Costs Act, is part of today's markup. It is
287 another effort to make sure surging demand from these massive

288 projects doesn't land on the backs of residential ratepayers.

289 Both of these bills are good first steps, Mr. Chairman,
290 but we should also be honest about what they don't do. They
291 don't fully address the water that these facilities draw from
292 our communities; they don't answer the concern back home that
293 when the grid is stretched families worry that they will be
294 deprioritized. People in the district that I represent are
295 raising these questions, and they deserve answers. That is
296 exactly why, when Congressman Obernolte and I drafted the
297 Great American AI Act, we included provisions to make data
298 centers more efficient and lessen their environmental
299 footprint because the smarter that we build these facilities,
300 the less strain they put on the grid, on our water, and on
301 the families who live nearby.

302 So these bills can't be where our work ends. AI is
303 spreading through every corner of our economy, and hard-
304 working Americans cannot be an afterthought while that
305 happens. I commend the sponsors of this legislation and the
306 committee staff for their work. It really matters, and I
307 look forward to continuing this track record of bipartisan
308 work on AI in the weeks and months ahead. Thank you.

309 *The Chair. Thank you. The gentlelady yields back. Is
310 there anyone on the Republican side?

311 The gentlelady from Tennessee is recognized for five
312 minutes to speak on the bill.

313 *Mrs. Harshbarger. Thank you, Mr. --

314 *The Chair. We are not speaking on the ANS, we are
315 speaking on the bill.

316 *Mrs. Harshbarger. Yes.

317 *The Chair. All right, thank you.

318 *Mrs. Harshbarger. Speaking on the bill, not the ANS.
319 Thank you, Mr. Chairman. I move to strike the last word.

320 *The Chair. The gentlelady is recognized to speak on
321 the bill.

322 *Mrs. Harshbarger. Americans should not be forced to
323 unfairly shoulder the cost of new generation if the demand is
324 driven by data centers. That is why I would like to thank
325 Rep. Evans for his bill, the Ratepayer Protection Act. This
326 legislation makes clear that states should consider how large
327 electricity demands from data centers affect residential
328 customers and existing businesses. And under this
329 legislation states must consider how a rate structure can be
330 appropriately differentiated among customer classes, ensuring
331 the costs associated with new growth are borne by those
332 driving that demand.

333 Combined with President Trump's Ratepayer Protection
334 Pledge and FERC's recent show cause orders, the Ratepayer
335 Protection Act demonstrates our shared commitment to support
336 transparency in rates and prevent a fair cost shifting. So I
337 applaud these efforts, and I urge my colleagues to vote in

338 favor of this legislation.

339 And with that I yield back.

340 *The Chair. The gentlelady yields back? The gentlelady
341 yields back. The gentlelady from Michigan is recognized for
342 five minutes to speak on the bill.

343 *Mrs. Dingell. Thank you, Mr. Chair.

344 I would like to thank first Congressman Evans and
345 Congresswoman Castor for their leadership on this bill. And
346 I thank both of you, Mr. Chair and Ranking Member Pallone,
347 for bringing this legislation before the committee today.

348 This issue is an issue I hear about every day when I am
349 home. Communities are not happy with what is happening.
350 They don't like it when they read a headline that says the
351 utility company will not give them the opportunity for input.
352 What is going to happen to them? And I want to say
353 communities deserve to know what is happening in their
354 backyard, and deserve a real voice in the process. Across my
355 district I hear from families, local officials, community
356 leaders who are worried about rising energy costs, increased
357 strain on the grid, water usage, and the broader impacts
358 these facilities may have on local infrastructure and
359 municipal resources.

360 Residential energy prices have increased at twice the
361 rate of inflation since the pandemic, and energy usage at
362 data centers is expected to more than double by 2030. People

363 across the country are asking a simple question: Are they
364 going to be left footing the bill for these enormous energy
365 demands created by some of the wealthiest corporations in the
366 world?

367 Our communities deserve a full, complete, and accurate
368 understanding of these projects, including clear transparency
369 about impacts on local energy demand, water usage, noise
370 pollution, public safety, emergency response capacity, and
371 municipal resources. These big tech companies have invested
372 billions of dollars in data centers, but too often
373 communities are left wondering whether they will be footing
374 the bill for big tech's increased energy usage and costly
375 grid upgrades made necessary by these facilities. This is
376 why we need responsible guardrails, transparency, and
377 accountability to ensure these projects benefit our workers,
378 our neighbors, the users of both electricity, water, and
379 local communities alike.

380 The Ratepayer Protection Act is a strong first step
381 towards ensuring that local communities are not forced to
382 subsidize these energy demands through higher utility bills
383 while big tech companies reap the profits. I am going to be
384 supporting this bill, but I also want to make it clear there
385 is more work to do to ensure communities receive the
386 transparency, the accountability, and the engagement they
387 deserve for those seeking to operate in their backyard. I

388 urge my colleagues to support H.R. 9340.

389 Thank you, Mr. Chair, and I yield back.

390 *The Chair. The gentlelady yields back, and I think I -
391 - I know I can speak for the entire committee. There have
392 been a lot of thoughts and prayers for you and your family
393 this week. God bless.

394 Are there any Republicans waiting to speak on the bill?

395 Seeing none, the gentleman from Florida is recognized.
396 The gentleman from Florida is recognized for five minutes to
397 speak on the bill.

398 *Mr. Soto. Thank you, Chairman.

399 We must focus on empowering communities when we are
400 talking about data centers. We are seeing data centers
401 cropping up all across the country, including in Florida.
402 They are needed for the cloud, for data storage, for AI, for
403 our economic future. But the electricity and water demands
404 are great. So is the noise, the emergency response, and so
405 many other demands on communities. So we need protections
406 for our constituents. We need rules of the road.

407 First, local constituents, cities, and county
408 commissioners must have the ultimate say whether a data
409 center is located in their community. It is absolutely
410 essential that our locals get to decide siting.

411 And second is what this bill addresses: long-term power
412 and water agreements, infrastructure all designed to help

413 protect the ratepayers, especially as energy prices continue
414 to go up. The Ratepayer Protection Act is a major step in
415 the right direction. State utilities can charge special
416 rates to fully recover costs. All new contracts of 100
417 megawatts or more would be included in this bill, and even
418 some potential upfront financial assurances.

419 But we have more work to do. The new infrastructure law
420 that is being debated in Congress does not include water or
421 electric infrastructure yet. Now, you may recall about five-
422 plus years ago, when we passed the Bipartisan Infrastructure
423 Law, it did include water improvements, it did include
424 electric improvements. We need to dig deep and make sure
425 that, when we ultimately pass an infrastructure law, it
426 includes roads, ports, airports, water, and electric, and be
427 ready for the new needs of the nation. The future of our
428 economy is at stake and is -- and our constituents are
429 counting on us.

430 And I yield back.

431 *The Chair. The gentleman yields back. Is there anyone
432 on the Republican side?

433 Seeing none, the gentlelady from Texas is recognized for
434 five minutes to speak on the bill.

435 *Mrs. Fletcher. Well, thank you, Chairman Guthrie, and
436 I want to thank Ranking Member Castor and Congressman Evans
437 for their leadership on the Ratepayer Protection Act. I am

438 proud to support this legislation that protects the existing
439 ratepayers. That is, the people in our communities that are
440 already paying the bills and -- to do the work to protect
441 them from -- and making sure that, you know, large new loads
442 bear the costs that they impose on the system that we use to
443 get our electricity.

444 In Texas we have seen similar actions from state
445 regulators, and I am really glad that we are talking about
446 these principles and ideas at the Federal level. In Texas we
447 have seen dramatic data center development and planned
448 development. The Texas Tribune recently reported that there
449 are 582 operating and planned data centers across Texas,
450 potentially adding more than 400,000 megawatts of demand to
451 the grid. And so this just really rapid and totally
452 unprecedented growth in power demand has left many of the
453 people that I represent concerned about access to reliable
454 and affordable energy, and I know that is true for people
455 across the country.

456 But certainly after our experience with Winter Storm
457 Uri, reliability is top of mind for people across the State
458 of Texas, and affordability is also top of mind for everyone
459 everywhere. I think that this bill is really an important
460 first step to address these concerns, but there are
461 additional opportunities for the committee to strengthen the
462 grid while keeping costs down.

463 And so I have heard from my constituents a lot of the
464 innovative ideas and things that people are talking about in
465 Texas. There are a broad range of stakeholders that have
466 practical, bipartisan ideas particularly around demand
467 response and innovative load management that I think deserve
468 further exploration from our committee as we continue to
469 address rising energy demand from every possible angle. So I
470 hope we will continue exploring policies on this committee
471 and in this Congress that encourage demand flexibility and
472 other innovative solutions that can protect ratepayers from
473 high costs.

474 Thank you. With that I yield back.

475 *The Chair. Thank you. The gentlelady yields back. Is
476 there anyone on the Republican side?

477 The gentlelady from California is recognized for five
478 minutes to speak on the bill.

479 *Ms. Barragan. Thank you, Mr. Chairman. I support the
480 Ratepayer Protection Act because it recognizes an important
481 principle, and that is that families and small businesses
482 should not be forced to subsidize the energy demands of AI
483 data centers.

484 Now, requiring states to consider whether data center
485 developers should bear the costs for the electric grid is a
486 meaningful first step toward protecting ratepayers, but
487 Congress must build on this work. This is not going to be

488 enough. We need to do more to ensure that families are
489 protected from higher electricity costs while also addressing
490 the health and the environmental impacts that the rapid
491 growth of AI data centers can cause in communities.

492 We have seen what has happened in other communities like
493 Memphis and in north Mississippi, where a company brought in
494 methane gas turbines to power its AI data centers. They
495 started running these turbines without any consideration
496 about protecting communities from dangerous air pollution.
497 And Easter Knox, a 76-year-old resident of Boxtown says those
498 consequences are deeply personal. She says that she stopped
499 having to open her windows because the air outside smells
500 like rotten cabbage. This should not happen in our
501 residential neighborhoods if people can't even open up their
502 windows anymore.

503 Another resident, a young Black registered nurse who
504 lives less than a mile from the gas turbines, hears them day
505 and night. She has to wear earplugs to sleep. Imagine that:
506 you have to wear earplugs in your own home to sleep because
507 of the noise from the turbines. And she worries that simply
508 spending time outside means breathing pollution that could
509 one day leave her with asthma or worse.

510 This is an environmental justice issue and a public
511 health crisis that no one should have to face. America can
512 lead in AI and innovation without asking communities to pay

513 the price on their utility bills or with their health. So as
514 we continue this work, Congress must ensure that data center
515 developers bear not just the cost of the electricity they
516 use, but the responsibility to build without sacrificing the
517 health of our communities.

518 I yield back.

519 *The Chair. The gentlelady yields back. Is anyone
520 seeking recognition on the Republican side?

521 Seeing none, the gentleman from Louisiana is recognized
522 for five minutes.

523 *Mr. Carter of Louisiana. Thank you, Mr. Chairman.

524 *The Chair. To speak on the bill.

525 *Mr. Carter of Louisiana. I am proud to support the
526 Ratepayer Protection Act, a bill to help protect American
527 families from paying the cost of energy and grid upgrades
528 required for new data centers.

529 We are witnessing something transformative in my home
530 state of Louisiana, where Meta recently announced that its
531 planned Hyperion data center in Richland Parish has grown
532 from a \$10 billion project to a supercluster now topping \$50
533 billion. Once complete, it will be one of the largest data
534 center projects in the world, with capacity to draw five
535 gigawatts of power at full operation, roughly the equivalent
536 of powering four million homes. That kind of investment can
537 deliver real, tangible benefits, such as thousands of

538 construction and operation jobs and new tax revenue windfalls
539 to fund 50,000 bonuses for Richland Parish teachers and
540 overdue infrastructure for improvements. But these projects
541 only work for communities if long term they are built on a
542 fair foundation.

543 When a single customer needs as much power as a major
544 city, someone has to pay for the transmission lines,
545 substations, and generation capacity to serve them. Those
546 shouldn't fall on retired residents on a fixed income or
547 small businesses in their town. That is exactly why the
548 Ratepayer Protection Act addresses these issues so finely.
549 It has established -- establishes a Federal standard for
550 utility regulators to apply when these hyper-scale projects
551 come before them for approval, helping ensure that owners of
552 these large-scale projects pay the full cost of the grid
553 upgrades of their -- that their operations require, not
554 passed on to families and small businesses.

555 And importantly, this isn't Washington dictating
556 outcomes to Louisiana. This bill doesn't force state
557 regulators to adopt any specific rate structure; it sets a
558 Federal standard for state utility commissions to consider.
559 This -- then use their own judgment to decide whether and how
560 to apply it. As a former utility regulator, I can certainly
561 appreciate the significance of this tool. Local officials
562 know the needs of their area better than anyone else. This

563 bill gives them a strong framework and a starting point from
564 which to operate while preserving the flexibility to tailor
565 solutions that fit each community's unique mix of growth,
566 infrastructure, and ratepayers.

567 Many Americans are understandably concerned about the
568 growth of data centers, in part because of how these projects
569 affect their monthly utility bills. Passing this measure is
570 small -- is a small but a proactive step for Congress to
571 ensure that companies profiting from these projects not only
572 enjoy the largesse, but that everyday ratepayers do not foot
573 the bill.

574 Mr. Chairman, I yield.

575 *The Chair. Thank you. The gentleman yields back. Is
576 there anyone on the Republican side?

577 Seeing none, the gentlelady from -- well, the Republican
578 side, we do have one.

579 [Laughter.]

580 *The Chair. The gentlelady from North Dakota -- I was
581 looking to my right, sorry -- the gentlelady from North
582 Dakota, the gentlelady from North Dakota is recognized for
583 five minutes for the -- to speak on the bill.

584 *Mrs. Fedorchak. It is okay, Mr. Chairman. I am
585 sitting on the other side. Thank you, Mr. Chairman.

586 First I want to thank my friends, Gabe Evans and Kathy
587 Castor, for their bipartisan work on the bill, the Ratepayer

588 Protection Act.

589 This legislation is an important step towards protecting
590 American families from increased electricity costs attributed
591 to growth in data centers other -- and other hyperscalers.
592 At its core, this issue comes down to a very simple
593 principle: Those who cause costs should pay for those costs
594 on our transmission grid and our energy systems. For decades
595 regulators, utilities, and consumer advocates have agreed on
596 this principle. If a customer or class of customers creates
597 a need for a new infrastructure, the costs associated with
598 serving that demand should be borne by those customers and
599 those who benefit from it, not shifted on to everybody else.

600 That principle is especially important today as we see
601 unprecedented growth in large loads across our country. We
602 want manufacturing, innovation, artificial intelligence, and
603 economic growth, but we must pursue that growth in a way that
604 protects families and small businesses from subsidizing
605 infrastructure that is primarily needed to serve others.

606 Thankfully, the states are on the front of this
607 conversation: 36 states, including D.C., have already
608 finished or are in the process of filing methods to ensure
609 that these large-load customers pay their fair share when
610 joining our electric grid. These actions are protecting
611 American families and the economic prosperity of the nation
612 we all call home because, if done correctly, new large loads

613 can provide real benefits to our society.

614 If done correctly, large loads can lower costs for our
615 families and make vital new investments in our grid, our
616 roads, and our schools. New load can strengthen the system,
617 improve asset utilization, and help lower costs for existing
618 customers rather than increasing them. In my home state of
619 North Dakota we have worked carefully to structure rates for
620 customers and large-load customers so that they cover the
621 costs -- the large loads cover the costs that they cause.
622 Through this, we have -- in one project alone we have saved
623 customers \$30 million. But that only works when we maintain
624 the principle that cost causers pay.

625 Families should not be asked to subsidize infrastructure
626 built to serve some of the largest and most sophisticated
627 companies in the world. Likewise, businesses making major
628 investments deserve transparency and certainty about the
629 costs that they will bear. Getting cost allocation right
630 protects hard-working Americans, supports economic
631 development, and helps build the infrastructure needed to
632 meet the growing demand. What we are considering today is an
633 important step.

634 We can and should follow this with additional work to
635 guide and direct cost allocation for transmission lines to
636 protect ratepayers and promote affordability. I look forward
637 to working with my colleagues and the committee staff in that

638 end, and I appreciate the bipartisan work that has gotten
639 this bill forward today.

640 Mr. Chairman, thank you and I yield back.

641 *The Chair. Thank you. The gentlelady yields back.

642 The gentlelady from Virginia is recognized for five minutes
643 to speak on the bill.

644 *Ms. McClellan. Thank you, Mr. Chairman, and I am proud
645 to support the Ratepayer Protection Act and thank
646 Representatives Evans and Castor for their leadership on this
647 important issue.

648 Over the past year energy prices have skyrocketed,
649 especially in the wake of the President's war of choice in
650 Iran. And with demand for energy driven by data centers,
651 electrification, and advanced manufacturing, we must
652 fundamentally change how we think about the grid and its
653 reliability, and place renewed urgency on our efforts to
654 rapidly bring more energy online while protecting consumers
655 from the impacts of a rapid build-out of data center
656 infrastructure.

657 Some projections show that data center energy
658 consumption could double or triple by 2028, accounting for up
659 to 12 percent of U.S. electricity use. The current
660 regulatory treatment of these costs is unsustainable.

661 Virginia is the data center capital of the globe, with
662 over 600 operational and over 400 more planned. After over

663 20 years of data center growth, we are grappling with the
664 impact of that status on the grid and on the electric bills
665 of consumers and small businesses. And what Virginia's
666 experience makes clear is that, as we build the
667 infrastructure necessary to support unprecedented electricity
668 demand, we must also ensure that the cost of serving that new
669 demand are borne by those who create it, not consumers and
670 small businesses already struggling to pay for their electric
671 bills.

672 Virginia's utility regulators are actively considering
673 reforms to ensure that the cost of transmission
674 infrastructure, built primarily to serve large-load customers
675 like data centers, are appropriately assigned to those
676 customers, rather than shifted onto residential ratepayers
677 and small businesses. Our state Corporation Commission has
678 already established a separate rate class for Dominion Energy
679 for hyperscale data centers specifically to reduce cost
680 shifting and protect consumers. And that is why I am glad to
681 support this concrete first step in the right direction to
682 ensure that consumers don't subsidize the infrastructure
683 necessary to meet explosive commercial load growth, but
684 rather shift the cost burden to the companies that benefit
685 the most.

686 At the same time, as I have said time and time again, we
687 must also bring new renewable energy sources and battery

688 storage online in a much more significant way than we have
689 this past year. Solar and wind provide a cheap, reliable,
690 and readily available source of energy to meet these growing
691 needs and keep energy prices in check. So while I urge my
692 colleagues to support the Ratepayer Protection Act, this
693 cannot be the final step.

694 I urge the committee to work in a bipartisan fashion to
695 further protect Americans from the increasing impacts of data
696 centers and, with that, I yield back.

697 *The Chair. The gentlelady yields back. Is there any
698 further discussion on the bill?

699 The gentleman from California is recognized for five
700 minutes to speak on the bill.

701 *Mr. Obernolte. Thank you, Mr. Chairman. I am
702 delighted that we are here today debating the Ratepayer
703 Protection Act to --

704 *The Chair. Will the gentleman suspend?

705 We are going to try to fix the mike real quick. I am
706 sorry, I meant to -- I was supposed to wait for them to do --
707 to reset.

708 Okay, the gentleman is recognized.

709 *Mr. Obernolte. Thank you, Mr. Chairman. I am
710 delighted that we are here today debating the Ratepayer
711 Protection Act which will give Americans some assurances that
712 when an AI data center is constructed it will not drive up

713 their residential electric rates. And there are a couple of
714 important reasons why this is so critical.

715 We all know that building the data centers that provide
716 the compute that make AI run is going to be critical to
717 having the United States maintain its leadership in the
718 development and the deployment of frontier AI, which will
719 probably be the most important tool for driving increased
720 worker productivity in our country and throughout the world
721 that mankind has ever invented. But it is also important
722 because we have a public perception problem, and our
723 geopolitical adversaries such as China and Russia are
724 investing vast sums of money in trying to influence public
725 opinion against data centers.

726 And if anyone here on the panel has doubts about that, I
727 urge you to go to a SCIF, get a classified briefing on this.
728 It is very eye-opening. They are doing this through state
729 media messaging, overtly and also covertly through covert
730 social media operations and covert advocacy networks. What
731 they want is for us to stop building data centers because
732 they think that that is the best way that they can catch up
733 and surpass us in AI development and deployment. So I think
734 it is important to be clear-eyed about this.

735 It is also important that we explain the truth to our
736 constituents, and the truth is, if you are a hyperscaler
737 right now looking to invest 1 to \$10 billion in a new data

738 center, the number-one thing you are worried about is where
739 your power is coming from. And so what you want to do is you
740 want on-site generation that is behind the meter that you
741 control. And if you can't get that, you want a local
742 provider to build new generation and dedicate it to you. And
743 either one of those things, you want to pay for that to make
744 sure that you have access to 100 percent reliable baseload
745 energy.

746 In either of those scenarios, if you are bringing
747 generation with you, you are going to size that generation to
748 100 percent of the maximum that you will ever use. And
749 because generation is most efficient when it runs at 100
750 percent maximum load, you are actually going to over-generate
751 when you turn your data center on, and you are going to sell
752 the excess energy back onto the grid. And ironically, folks,
753 that drives down residential electric rates, not up. So that
754 is the reality.

755 And so I am very glad that we are here debating a bill
756 that is going to make it clear to the American public that
757 their rates are not going to go up as a result of data
758 centers, but we need to do more to try and evangelize this,
759 because we have got states like New York who this week
760 imposed a one-year ban, a moratorium on the construction of
761 new data centers in the state.

762 And honestly, I was going to offer an amendment to the

763 bill kind of tongue in cheek today. I am not going to do it
764 because, you know, it is -- we are doing some serious
765 legislating and this was not a lawmaking effort. I was going
766 to offer an amendment that said if you are a state and you
767 are going to impose a moratorium on data center construction,
768 that is fine, you have the right to do that, but guess what?
769 No compute for you, right? Which is fair, because why is it
770 -- why should a state say we want access to all the compute
771 the data centers provide and all the productivity that is
772 going to add to our workforce and the ability to do cloud
773 storage, but we are not going to allow that to be built on
774 state territory. It is just nonsensical.

775 So I am delighted that we are going to pass this today
776 with broad bipartisan support, but I think it is important
777 also that we communicate clearly with the American public
778 what the situation is with data centers and water usage and
779 power usage, and, most importantly, the fact that our
780 geopolitical competitors are actively investing in trying to
781 poison American public opinion against these data centers.

782 With that, Mr. Chairman, I yield back.

783 *The Chair. Thank you. The gentleman yields back. Is
784 there any further discussion on the bill?

785 The gentlelady from New York is recognized for five
786 minutes to speak on the bill.

787 *Ms. Ocasio-Cortez. Thank you. You know, just as a

788 alternative point of consideration here in terms of New York
789 State's recent moratorium, you know, the kind of thought
790 that, well, you know, if you don't want to build in your
791 backyard then maybe you shouldn't have access to compute, we
792 could say the same thing about Silicon Valley. We could say
793 the same thing about Silicon Valley billionaires that are
794 constructing and pushing and imposing these data centers on
795 communities that are overwhelmingly rural, disenfranchized,
796 poor, and whose own elected officials are not being
797 transparent about how the land use is happening in their own
798 backyard.

799 Because I would reckon -- you look around. Ask Peter
800 Thiel, ask Elon Musk, ask Mark Zuckerberg if they want one of
801 these data centers in their own backyard. Ask any one of us
802 here on this committee. If anyone wants to live right next
803 to one of these data centers here on this committee, please
804 raise your hand because I have been going to -- I have
805 visited Georgia. I was just in Memphis on Friday. There was
806 an xAI graywater treatment plant on one street corner across
807 the street from methane turbines, another -- all within one
808 block -- methane turbines, coal ash, wastewater facilities.
809 And everyone in that area is getting poisoned.

810 I think that so many of us -- at the end of the day,
811 this conversation is not just about technology; it is about
812 people's ability to live without getting cancer, people's

813 ability to have a home that doesn't get cracked up in their
814 foundations because this construction is going on that their
815 city council is not informing them of, that their county
816 commissioners are not being transparent about, and that
817 people aren't voting on. And the idea that that is all just
818 kind of a foreign operation, I think that if you actually
819 talk to these people in these communities they would
820 disagree.

821 Just this -- and on top of that, in New York it is not
822 just the electricity bills, it is the water. We have one of
823 the precious -- most precious and sacred water supplies in
824 the United States. Once you compromise that, it is done.
825 Ask people in Flint. Ask people across the country. When
826 their critical water supplies are compromised, it takes
827 years, if not decades, to clean up again.

828 So I think what people are asking for in their basic
829 protections is not too much to ask. They want to make sure
830 that their water isn't going to be poisoned, which -- these
831 data centers come in, they say it is not going to be a
832 problem, and then you all saw. We brought the well water
833 right here. So we need to have protections in place for
834 people.

835 And when we talk about increased worker productivity,
836 that is because millions of people stand to lose their jobs.
837 And so you have people where -- we are seeing some of the

838 output of AI, increased productivity per role, and we are
839 seeing lots of companies talk about how many people you can
840 lay off with this technology. What is the plan? And I think
841 it is not unreasonable for the working-class people that we
842 are elected to respond to, to ask questions and to deserve
843 and feel entitled to a response from their elected officials.
844 That is all.

845 And with that I yield back.

846 *Mr. Pallone. Would I -- would the gentlewoman yield to
847 me?

848 *Ms. Ocasio-Cortez. Yes.

849 *Mr. Pallone. Let me associate myself with the remarks
850 you made. And I have to say, when I heard the gentleman from
851 the other side of the aisle talk about, you know, China,
852 Beijing, foreign conspiracies -- I don't know exactly what he
853 said -- I assure you that the towns in my district -- one of
854 them decided to get rid -- to not approve a data center.
855 Another one decided to ban data centers. Several have
856 decided to have moratoriums on data centers. They are not
857 being influenced by China and Russia; they are looking at
858 exactly what is happening in their towns, as the gentlewoman
859 from New York said, and they are making these rational
860 decisions, adopting resolutions because they are concerned
861 about the local impact and they are also concerned about the
862 impact on ratepayers and the rates going up.

863 So I am not saying that the gentleman is suggesting --
864 on the other side is suggesting that this is all about, you
865 know, Beijing or whatever. But the bottom line is I want
866 everyone to understand that, when we talk about the need for
867 safeguards and the types of things that my colleague from
868 Florida is putting forth in this legislation, this is coming
869 from the people themselves. This is their concerns over
870 rates, over the environment. This is not Beijing.

871 I yield back to the gentlewoman.

872 *The Chair. The gentlelady yields back. The gentleman
873 from Alabama is recognized for five minutes to speak on the
874 bill.

875 *Mr. Palmer. Thank you, Mr. Chairman.

876 I just want to point out that there are options for
877 building data centers that don't involve building them in
878 neighborhoods or close to neighborhoods. There are 17 coal-
879 fired power plants that have been shut down in New York
880 State. Some of them have been repurposed, but there are
881 still a number of sites that would be available for
882 construction of a data center.

883 In regard to power for those facilities, many of my
884 Democratic colleagues and I are working on small modular
885 nuclear as an option for that so that you can build these
886 facilities behind the meter so that they don't impact the
887 grid.

888 But the thing that I think is most promising about
889 putting these facilities on what was once a coal-fired power
890 plant is the transmission lines remain intact, and many of
891 those are usable. You could not only put a data center on a
892 on a coal-fired -- formerly coal-fired power plant site and
893 power it without connecting to the grid, you could add
894 additional power generation there to increase the baseload
895 power available for communities around which would lower
896 their utility costs.

897 So I think I -- you know, I am in agreement that we
898 don't want to build them next to a subdivision or in a
899 heavily populated area. We don't have to. We have got many
900 options. And it is not just the coal-fired power plant
901 sites; there are other brownfield sites that many states are
902 working very hard to repurpose.

903 And I think we need to come to an agreement in regard to
904 the importance of data centers in the context of the arms
905 race that we are in with China for dominance in artificial
906 intelligence. And I have said this time and time and time
907 again in this committee, that this arms race, whoever wins
908 it, will not be a superpower; they will be the superpower.

909 We are forgetting so many other parts of the value
910 proposition for data centers and what -- the potential for AI
911 in medicine. I made this point in a meeting a couple of days
912 ago and again last night, that we are dealing with diseases

913 like dementia and Parkinson's and other things where an AI-
914 generated medical research effort could do millions of
915 iterations of complex proteins, millions of iterations of
916 molecular DNA, millions of iterations of the make-up of
917 pharmaceuticals that could be done in a matter of minutes so
918 that we could go from treatment to possibly cure.

919 I just think that we lose -- because of the partisanship
920 sometimes and the misinformation, we lose -- we are
921 forgetting the value proposition that is presented by
922 artificial intelligence and the data centers. And we need to
923 be working together to find a way to get these facilities
924 built so that we do not lose the arms race to China.

925 I yield back.

926 *The Chair. The gentleman yields back. Is there
927 further discussion?

928 The gentlelady from Colorado is recognized for five
929 minutes to --

930 *Ms. DeGette. Thank you.

931 *The Chair. -- speak on the bill.

932 *Ms. DeGette. Thank you so much, Mr. Chairman. There
933 -- I know this bill is trying to begin addressing the issue
934 of data centers, but there are some big gaps in the bill.

935 And the gentlelady from New York talked a little bit
936 about some of the water issues around data centers, and I
937 appreciate that from the standpoint of a New Yorker. I am

938 from Colorado, the West. And in the West we have a chronic
939 shortage of water, but we are also in the middle of a
940 historic drought right now. The bill doesn't even address
941 water usage and water quality, which is going to be a unique
942 concern for Colorado but for the entire West as the drought
943 worsens due to climate change.

944 And also, as the gentlelady mentioned, there are costs
945 associated with water -- wastewater treatment because we need
946 to make sure that the water quality for those communities
947 around data centers continues to have integrity. Otherwise,
948 it will be passed along to the consumers. Let me give just
949 an example.

950 Data centers around Phoenix, Arizona use about 385
951 million gallons of water per year for cooling, and that
952 doesn't even count the water that they are using to generate
953 the electricity they need to operate. The figure will grow
954 more as data centers are built. The facility's direct water
955 consumption may skyrocket to 3.7 billion gallons annually.
956 Just to put it into perspective, that would be enough to
957 supply 34,000 homes.

958 Now, in the cooling process a data center can use up to
959 5 million gallons of water every day, as much as 16,000-plus
960 average U.S. households, according to EPA estimates.
961 Generating the electricity to keep data centers powered up
962 requires additional millions of gallons of water. About two-

963 thirds of the data centers built since 2022 are already
964 expressing water stress, according to Bloomberg News. Data
965 center cooling systems often use chemical additives to
966 prevent corrosion scaling and the growth of algae and
967 bacteria, and also they might have refrigerants and PFAS in
968 them.

969 And finally, a lot of the data centers are just simply
970 hooked up to the local water mains, meaning that the data
971 center's cooling water comes from potable sources like
972 municipal water or groundwater. Eighty to ninety percent of
973 this water is consumed from watersheds like lakes, rivers, or
974 aquifers.

975 There are a number of solutions for addressing water
976 issues like requiring better water use disclosure, reviewing
977 projects by watershed. For example, a gallon of water in
978 Arizona or Colorado is not the same as a gallon of water in
979 Virginia, Georgia, or Pennsylvania. And reviewing water and
980 energy issues together, not as separate issues. And so that
981 is why I say that, as we are looking at how we are going to
982 manage what -- data centers in the vast stretches of the
983 western United States, water is going to be the key component
984 and we need to think about that beforehand, not once those
985 thousands and thousands of homes can't get built or can't get
986 water because of data centers.

987 I yield back.

988 *The Chair. Thank you. The gentlelady yields back. Is
989 there any further discussion on the bill?

990 The gentleman from Pennsylvania is recognized for
991 five --

992 *Mr. Joyce. Thank you, Mr. Chairman. I yield to the
993 gentleman from Alabama, Mr. Palmer.

994 *Mr. Palmer. I thank the gentleman from Pennsylvania
995 for yielding.

996 And again, what was just described has been used in the
997 past, but data centers are moving to different technologies
998 for cooling. One of them is a glycol-based heat transfer
999 system that doesn't impact your water system. But what a lot
1000 of them are using now is a closed-loop cooling system that is
1001 recirculating water. It is similar to the radiator in an
1002 automobile, which is a closed-loop system. So you are not
1003 using millions of gallons of water from the local community
1004 for cooling.

1005 I just thought that it might be of interest to point out
1006 those technical aspects, and I yield back to the gentleman.

1007 *Mr. Joyce. I yield back, Mr. Chairman.

1008 *The Chair. The gentleman from Pennsylvania yields
1009 back. Is there any further discussion?

1010 Seeing no further discussion, are there any amendments?

1011 The gentleman from Colorado is recognized -- for what
1012 purpose does the gentleman from Colorado seek recognition?

1013 *Mr. Evans. Thank you, Mr. Chairman. I have an
1014 amendment in the nature of a substitute at the desk,
1015 ANS_TARIFF_01_XML.

1016 *The Chair. The clerk will report the amendment.

1017 *The Clerk. Amendment in the nature of a substitute to
1018 H.R. 9340 offered by Mr. Evans of Colorado --

1019 *The Chair. Without objection, the reading of the
1020 amendment is dispensed with.

1021 [The amendment of Mr. Evans follows:]

1022

1023 *****COMMITTEE INSERT*****

1024

1025 *The Chair. And the gentleman from Colorado is
1026 recognized for five minutes in support of the amendment.

1027 *Mr. Evans. Thank you, Mr. Chairman. This is a simple
1028 amendment with bipartisan support to ensure that H.R. 9340,
1029 the Ratepayer Protection Act, addresses the understandable
1030 concern Americans have about their electric bills as
1031 utilities race to meet the unprecedented growth in energy
1032 demand.

1033 This amendment just refines the definition of a large
1034 load customer in the proposed Federal standard to narrowly
1035 tailor this bill to address new data centers and hyperscalers
1036 over 100 megawatts of peak demand. It is a direct reflection
1037 of the intent of the bill to respond to community members'
1038 concerns about the costs of data center development and
1039 action policies that address those large loads.

1040 Keeping costs low for ratepayers is essential, and this
1041 amendment ensures just that through refining the language. I
1042 urge bipartisan support of the amendment.

1043 And I yield back.

1044 *The Chair. The gentleman yields back. Is there
1045 further -- the gentlelady from Florida is recognized to speak
1046 on the amendment.

1047 *Ms. Castor. Well, thank you, Mr. Chairman. I move to
1048 strike the last word in favor --

1049 *The Chair. The gentlelady is recognized.

1050 *Ms. Castor. Great, thank you.

1051 Colleagues, I appreciate all of the bipartisan support
1052 for the Ratepayer Protection Act and a lot of the thoughtful
1053 comments during the discussion on the bill today because
1054 electric bills for hard-working Americans are sky high. Just
1055 over the past year and a half they are up, on average, over
1056 18 percent. Folks back home in Florida are really grappling
1057 with skyrocketing electric bills, and now we have these huge
1058 hyperscale data centers that could send bills soaring even
1059 higher unless we act, and that is why I am leading the
1060 Ratepayer Protection Act with my colleague, Representative
1061 Evans of Colorado. And the Act says that if a company wants
1062 to build a data center, the data center should pay for the
1063 power and upgrades that it needs, not families, not farmers,
1064 not small businesses, not communities back home.

1065 When a large data center comes online, it can trigger
1066 massive upgrades: new power plants, transmission lines,
1067 local transformers. And those costs can be passed on to all
1068 ratepayers, and that is not fair. Our neighbors should not
1069 be stuck paying for the energy infrastructure for the
1070 wealthiest companies in the world. The Ratepayer Protection
1071 Act says that the data center pays for its own upgrades, not
1072 the rest of us.

1073 This is about fairness. It is about making sure that
1074 when a data center corporation demands more electricity, they

1075 don't pass the cost on to people who already struggle with
1076 higher bills. It is about protecting our neighbors from
1077 hidden rate hikes and ensuring that the benefits of AI and
1078 innovation are shared by all, not just the corporations and
1079 the big tech companies.

1080 Yes, we are racing to lead the world in AI, but that
1081 race shouldn't come on the backs of families and small
1082 businesses. Instead, AI -- the benefits of AI and more
1083 affordable energy should reach everyone. That is what the
1084 Ratepayer Protection Act does. It makes sure that our grid
1085 serves everyone and that the companies who benefit pay their
1086 fair share.

1087 Now, many states are already acting here. This bill --
1088 or let me highlight a few of them. Many -- Virginia has
1089 established a tariff requiring data centers to cover 85
1090 percent of new transmission and distribution capacity costs.
1091 Minnesota requires data centers to pay into an energy
1092 conservation and weatherization fund to benefit working-class
1093 ratepayers. Kansas incentivizes data centers to participate
1094 in demand response to reduce peak demand. And back home in
1095 Florida, at least 20 counties and municipalities have passed
1096 or discussed a moratorium. But Florida state law now
1097 regulates data center energy and water use, and these actions
1098 are still allowed and they are even encouraged under this
1099 bill.

1100 I heard Representative McClellan from Virginia loud and
1101 clear, too. A lot of these data centers can be powered by
1102 cleaner, cheaper energy. There are -- there is a massive
1103 amount of clean, affordable energy waiting to come onto the
1104 grid. And Congresswoman Fedorchak highlighted the problem
1105 with interconnection. We should be working together now to
1106 unleash a lot of these clean energy resources that would help
1107 lower -- put pressure on lowering electric bills, and I hope
1108 that this bipartisan bill can help us chart a course there,
1109 too. Otherwise, we are going to continue to have this
1110 conflagration as we try to lead the world in AI.

1111 The call on power exceeds what we have, and we have the
1112 technological tools to do this. I am confident in the United
1113 States of America that we can work on upgrading the grid and
1114 bringing a lot of these cleaner, cheaper resources to bear.
1115 We have a partnership with a lot of the innovative companies,
1116 forward-looking regulators. We can use this opportunity to
1117 build a modern energy system that works for everyone.

1118 Our neighbors back home are counting on us to lower
1119 their electric bills and make life more affordable, and this
1120 bipartisan bill is an important first step. But let's keep
1121 going to lower energy bills and ensure that we have a modern
1122 grid to serve everyone.

1123 Thank you, Mr. Chairman, and I urge a yes vote on H.R.
1124 9340.

1125 *The Chair. Thank you. The gentlelady yields back. I
1126 now recognize myself for five minutes to speak on the
1127 amendment, and I support the amendment to H.R. 9340, the
1128 Ratepayer Protection Pledge. I really appreciate the hard
1129 work of the gentleman from Colorado and the gentlelady from
1130 Florida to get us where we are.

1131 This legislation signals the states that they should be
1132 sure individual households are not footing the bill for
1133 massive infrastructure build-out needed to win the race to AI
1134 dominance. The rapid proliferation of new, large-scale
1135 energy consumers connecting to the grid in such a short time
1136 has never been seen before, even exceeding our nation's
1137 response to World War II. But make no mistake, we are in an
1138 era -- a new era for the power sector. Whether you are a
1139 data center, a smelter, or a paper mill connecting new
1140 facilities to the electric system, we need more
1141 infrastructure to provide power for large loads. But in
1142 Congress we also must advance policy to protect reliability
1143 for communities and keep costs affordable.

1144 Importantly, states are also recognizing this reality
1145 and developing large-load tariffs for all kinds of customers
1146 in order to protect households. No matter the state or
1147 district, each of us here has heard concerns about data
1148 centers back home. This amendment takes an important step
1149 toward addressing those concerns.

1150 We have met with numerous stakeholders, including the
1151 data center industry, the big tech, state regulators,
1152 utilities, and others. And a lot of us, when we go home,
1153 hear from the most important stakeholder: our constituents.
1154 But it has become clear that across the entire industry there
1155 is one entity uniquely positioned to stand up for families
1156 and communities who are paying the electricity bills, and
1157 that entity is this committee and our colleagues here in
1158 Congress. President Trump called for this Ratepayer
1159 Protection Pledge, so we are effectively codifying the
1160 principles laid out. And we have come together to agree upon
1161 those principles. And the companies that signed the pledge
1162 agreed to pay for new infrastructure network upgrades needed
1163 to connect the grid, and those costs are not borne by
1164 residential ratepayers.

1165 There is no question that members of this committee have
1166 worked very hard this Congress to advance a pro-innovation
1167 agenda on winning the race for AI dominance, but we are
1168 showing today that on a bipartisan basis we can pursue an
1169 innovation agenda while simultaneously providing guardrails
1170 to protect consumers back home.

1171 As we talked about the race against China, it absolutely
1172 is true we are in a race against China. People estimate we
1173 are probably six months ahead if China is not catching up.
1174 And so, if we did a moratorium -- I think each state has the

1175 right to do what they want to do, each community. But if we
1176 did a nationwide moratorium and we did it for a year until we
1177 were -- China would be ahead, it would be difficult to catch
1178 up. So that is not the answer. But it is the answer to make
1179 sure that communities decide.

1180 In the principles for AI reform, we had the four Cs, one
1181 of them being community. Just like if Ford wants to build a
1182 large battery plant which they built in my district, they
1183 built it in an industrial park. You wouldn't want them to
1184 build it in a -- near -- right next to a neighborhood. There
1185 are local community and zoning laws that absolutely have to
1186 be respected that protect that area.

1187 And in terms of permitting, my friend from Florida has
1188 talked about this quite a bit. And we have to move forward
1189 between now and the end of the year on permit reform. We are
1190 going to make a move forward on that.

1191 But my friend from New York talked about the water that
1192 we had a hearing on in O&I. You know, that was a water
1193 system that had spent seven years working with the National
1194 Park Service to try to get a permit to repair the line that
1195 collapsed.

1196 And so, as we look at -- sometimes protecting things
1197 creates guardrails to fixing things that in the end don't
1198 protect things, and so that is all important.

1199 And I just want to finish with this time by saying I

1200 really appreciate the hard work of every member of this
1201 committee because the most important stakeholder in this
1202 business is our constituents, and we are all listening to
1203 them, we are all responding to them. And that is what this
1204 is about. Our staffs have worked very hard to get to where
1205 we are. I really appreciate it, and I think we are doing
1206 something big.

1207 And I appreciate the time and I will yield back. Is
1208 anyone seeking recognition to speak on the amendment?

1209 The gentleman from New York is recognized for five
1210 minutes to speak on the amendment.

1211 *Mr. Tonko. Thank you, Mr. Chair. I move to strike the
1212 last word.

1213 *The Chair. The gentleman is recognized to speak on the
1214 amendment.

1215 *Mr. Tonko. I thank you. I appreciate the committee's
1216 effort on this amendment in the nature of a substitute.

1217 At the subcommittee markup I raised two issues that I
1218 perceived with this bill's definition of large-load customer.
1219 First, the definition of large load is set at 100 megawatts,
1220 despite the fact that many states and PJM are opting for 50
1221 megawatts. Second, the definition was not limited to only
1222 data centers and crypto mining facilities, but rather to all
1223 large and non-residential electric consumers, which means
1224 large manufacturers will be captured by this policy.

1225 I have heard Republicans on this committee say over and
1226 over again that we are in a race against China to lead the
1227 world in AI, but we need to appreciate that we are also
1228 competing with the rest of the world to be the leader in many
1229 critical manufacturing industries. And we should be
1230 thoughtful and nuanced about how we tackle these very
1231 different types of businesses because not all loads or
1232 economic development opportunities, for that matter, are the
1233 same.

1234 This is especially true because energy-intensive and
1235 trade-exposed manufacturing like steel and aluminum is
1236 sensitive to electricity costs. Modest changes to energy
1237 prices can make or break a project, determining whether a
1238 company is going to invest in the United States or simply go
1239 elsewhere. And steel and aluminum manufacturing facilities
1240 are commonly larger than the 100-megawatt thresholds included
1241 in the bill.

1242 We are similarly seeing new advanced manufacturing
1243 gigafactories popping up across the country to produce
1244 semiconductors and batteries which can also be above this
1245 threshold. In recent years there have been both Democrats
1246 and Republicans calling for policies to promote reshoring and
1247 expanding of domestic manufacturing. Now that we are seeing
1248 the pay-off of those policies, we should avoid imposing new,
1249 unnecessary costs on these industries, undermining their

1250 ability to compete, and compete globally.

1251 So I appreciate the change in the amendment to address
1252 this second definitional issue. But now that we have
1253 rescoped the definition of "customer'', we should also
1254 reassess the megawatt threshold. Given the initial broad
1255 definition, I understood why the megawatt threshold was set
1256 at 100 rather than 50. That range of 50 to 100 megawatts
1257 would capture many more types of manufacturing facilities.
1258 So if the initial intent was to limit the number of
1259 manufacturers covered by the policy without explicitly
1260 excluding them, the 100-megawatt threshold was a mechanism by
1261 which to do so. But now that we are limiting the policy to
1262 computational loads, it makes sense to embrace the emerging
1263 consensus on the state level of 50 megawatts. Fifty
1264 megawatts is enough to power tens of thousands of homes. Of
1265 course, a 50-megawatt data center could trigger major grid
1266 upgrades and impose costs on ratepayers.

1267 If we really want to protect our constituents, we should
1268 make certain the right projects are covered by this
1269 legislation. While this amendment is a good start at
1270 correcting the initial definition, I encourage us to continue
1271 working to right-size the megawatt threshold.

1272 And with that, Mr. Chair, I thank you and yield back.

1273 *The Chair. The gentleman yields back, and the
1274 gentleman from Ohio is recognized for five minutes to speak

1275 on the amendment.

1276 *Mr. Latta. Well, thank you very much, Mr. Chairman.
1277 The bill and the ANS that data centers pay the costs of
1278 system upgrades to serve their demand so ratepayers aren't
1279 footing the bill. This is important to address the concerns
1280 of our constituents across the nation.

1281 The ANS provides the key principles for states to
1282 consider when establishing or approving rates for data
1283 centers. It in no way binds a state's hands or compels the
1284 state to undermine their state laws. It recognizes the
1285 states may take their own approach to protecting ratepayers
1286 from the new large loads on the power system. We know that
1287 many states are already doing this. Some are developing
1288 industrial tariffs to address concerns; others are developing
1289 large-load tariffs of different sizes. Others are developing
1290 large-load tariffs with flexibility depending on whether the
1291 customer is a data center or a traditional industrial
1292 facility. Others still are developing tariffs that just
1293 address data centers as a specific rate class, all within
1294 their legal authority.

1295 In Ohio a major tariff was approved last year just for
1296 data centers. In that case the state commission determined
1297 that data centers represent a distinct type of new load, and
1298 set a rate for those facilities as a class, just as it sets
1299 rates for other classes of commercial users. The commission

1300 did this to ensure other ratepayers aren't stuck with the
1301 bill if data centers do not use as much power as they
1302 requested. That is the benefit of state flexibility to find
1303 the best way to protect ratepayers from these large loads.

1304 This amendment and the underlying bill preserve state
1305 flexibility to design rates to cover large load costs and
1306 focus attention where it is needed most, protecting
1307 residential ratepayers. We need to support this ANS, and I
1308 urge a yes vote.

1309 And I yield back the balance of my time.

1310 *The Chair. The gentleman yields back. Is there a
1311 discussion on the amendment on the Democrat side?

1312 Seeing none, is there any further discussion -- the
1313 gentleman from Pennsylvania is recognized for five minutes to
1314 speak on the amendment.

1315 *Mr. Joyce. Thank you, Mr. Chairman.

1316 As we have seen an increased use of AI and, in turn, a
1317 higher demand for the data centers, I continue to hear
1318 concerns from my constituents that the development in their
1319 community will raise their electric rates. We want to remain
1320 competitive and win the AI race with China. That is clear to
1321 all of us. But that cannot come at the expense of
1322 affordable, reliable electricity for every American. That is
1323 why I am proud to cosponsor H.R. 9340, the Ratepayer
1324 Protection Act, and support this ANS which would narrow the

1325 original bill to focus on data centers specifically.

1326 If a data center developer works with the local
1327 community and secures the necessary local support to build in
1328 that area, then subsequently the ratepayers should never face
1329 an increased cost due to infrastructure upgrades that would
1330 be necessary to accommodate the project. This bill would
1331 make sure that data centers should shoulder the cost of any
1332 upgrades, and not the consumer. And I urge my colleagues to
1333 support the ANS and to also support the underlying bill, H.R.
1334 9340.

1335 Mr. Chairman, I yield back.

1336 *The Chair. The gentleman yields back. Is there
1337 further discussion on the amendment?

1338 Seeing none, if there is no further discussion, the vote
1339 occurs on the amendment.

1340 All those in favor shall vote by saying aye.

1341 All those opposed, no.

1342 The ayes have it, and the amendment is agreed to.

1343 Are there further amendments to the bill?

1344 Seeing none, the question now occurs on adopting H.R.
1345 9340, as amended. A roll call has been requested and the
1346 clerk will call the roll.

1347 *The Clerk. Mr. Latta?

1348 *Mr. Latta. Aye.

1349 *The Clerk. Mr. Latta votes aye.

1350 Mr. Griffith?
1351 *Mr. Griffith. Aye.
1352 *The Clerk. Mr. Griffith votes aye.
1353 Mr. Bilirakis?
1354 *Mr. Bilirakis. Aye.
1355 *The Clerk. Mr. Bilirakis votes aye.
1356 Mr. Hudson?
1357 [No response.]
1358 *The Clerk. Mr. Carter of Georgia?
1359 *Mr. Carter of Georgia. Aye.
1360 *The Clerk. Mr. Carter of Georgia votes aye.
1361 Mr. Palmer?
1362 *Mr. Palmer. Aye.
1363 *The Clerk. Mr. Palmer votes aye.
1364 Mr. Dunn?
1365 [No response.]
1366 *The Clerk. Mr. Crenshaw?
1367 [No response.]
1368 *The Clerk. Mr. Joyce?
1369 *Mr. Joyce. Aye.
1370 *The Clerk. Mr. Joyce votes aye.
1371 Mr. Weber?
1372 *Mr. Weber. Aye.
1373 *The Clerk. Mr. Weber votes aye.
1374 Mr. Allen?

1375 *Mr. Allen. Aye.
1376 *The Clerk. Mr. Allen votes aye.
1377 Mr. Balderson?
1378 [No response.]
1379 *The Clerk. Mr. Balderson?
1380 *Mr. Balderson. Aye.
1381 *The Clerk. Mr. Balderson votes aye.
1382 Mr. Fulcher?
1383 *Mr. Fulcher. Fulcher is aye.
1384 *The Clerk. Mr. Fulcher votes aye.
1385 Mr. Pfluger?
1386 [No response.]
1387 *The Clerk. Mrs. Harshbarger?
1388 [No response.]
1389 *The Clerk. Mrs. Miller-Meeks?
1390 *Mrs. Miller-Meeks. Yes.
1391 *The Clerk. Mrs. Miller-Meeks votes aye.
1392 Mrs. Cammack?
1393 [No response.]
1394 *The Clerk. Mr. Obernolte?
1395 *Mr. Obernolte. Aye.
1396 *The Clerk. Mr. Obernolte votes aye.
1397 Mr. James?
1398 [No response.]
1399 *The Clerk. Mr. Bentz?

1400 *Mr. Bentz. Aye.
1401 *The Clerk. Mr. Bentz votes aye.
1402 Mrs. Houchin?
1403 *Mrs. Houchin. Aye.
1404 *The Clerk. Mrs. Houchin votes aye.
1405 Mr. Fry?
1406 *Mr. Fry. Aye.
1407 *The Clerk. Mr. Fry votes aye.
1408 Ms. Lee?
1409 *Ms. Lee. Aye.
1410 *The Clerk. Ms. Lee votes aye.
1411 Mr. Langworthy?
1412 *Mr. Langworthy. Aye.
1413 *The Clerk. Mr. Langworthy votes aye.
1414 Mr. Kean?
1415 *Mr. Kean. Aye.
1416 *The Clerk. Mr. Kean votes aye.
1417 Mr. Rulli?
1418 *Mr. Rulli. Aye.
1419 *The Clerk. Mr. Rulli votes aye.
1420 Mr. Evans?
1421 *Mr. Evans. Aye.
1422 *The Clerk. Mr. Evans votes aye.
1423 Mr. Goldman?
1424 *Mr. Goldman. Aye.

1425 *The Clerk. Mr. Goldman votes aye.
1426 Mrs. Fedorchak?
1427 *Mrs. Fedorchak. Aye.
1428 *The Clerk. Mrs. Fedorchak votes aye.
1429 Mr. Pallone?
1430 *Mr. Pallone. Aye.
1431 *The Clerk. Mr. Pallone votes aye.
1432 Ms. DeGette?
1433 *Ms. DeGette. Aye.
1434 *The Clerk. Ms. DeGette votes aye.
1435 Ms. Schakowsky?
1436 *Ms. Schakowsky. Aye.
1437 *The Clerk. Ms. Schakowsky votes aye.
1438 Ms. Matsui?
1439 *Ms. Matsui. Aye.
1440 *The Clerk. Ms. Matsui votes aye.
1441 Ms. Castor?
1442 *Ms. Castor. Aye.
1443 *The Clerk. Ms. Castor votes aye.
1444 Mr. Tonko?
1445 *Mr. Tonko. Aye.
1446 *The Clerk. Mr. Tonko votes aye.
1447 Ms. Clarke?
1448 *Ms. Clarke. Aye.
1449 *The Clerk. Ms. Clarke votes aye.

1450 Mr. Ruiz?
1451 [No response.]
1452 *The Clerk. Mr. Peters?
1453 *Mr. Peters. Aye.
1454 *The Clerk. Mr. Peters votes aye.
1455 Mrs. Dingell?
1456 *Mrs. Dingell. Aye.
1457 *The Clerk. Mrs. Dingell votes aye.
1458 Mr. Veasey?
1459 [No response.]
1460 *The Clerk. Ms. Kelly?
1461 *Ms. Kelly. Aye.
1462 *The Clerk. Ms. Kelly votes aye.
1463 Ms. Barragan?
1464 *Ms. Barragan. Aye.
1465 *The Clerk. Ms. Barragan votes aye.
1466 Mr. Soto?
1467 *Mr. Soto. Aye.
1468 *The Clerk. Mr. Soto votes aye.
1469 Ms. Schrier?
1470 *Ms. Schrier. Aye.
1471 *The Clerk. Ms. Schrier votes aye.
1472 Mrs. Trahan?
1473 *Mrs. Trahan. Aye.
1474 *The Clerk. Mrs. Trahan votes aye.

1475 Mrs. Fletcher?
1476 *Mrs. Fletcher. Aye.
1477 *The Clerk. Mrs. Fletcher votes aye.
1478 Ms. Ocasio-Cortez?
1479 *Ms. Ocasio-Cortez. Aye.
1480 *The Clerk. Ms. Ocasio-Cortez votes aye.
1481 Mr. Auchincloss?
1482 *Mr. Auchincloss. Aye.
1483 *The Clerk. Mr. Auchincloss votes aye.
1484 Mr. Carter of Louisiana?
1485 *Mr. Carter of Louisiana. Aye.
1486 *The Clerk. Mr. Carter of Louisiana votes aye.
1487 Mr. Menendez?
1488 *Mr. Menendez. Aye.
1489 *The Clerk. Mr. Menendez votes aye.
1490 Mr. Mullin?
1491 *Mr. Mullin. Aye.
1492 *The Clerk. Mr. Mullin votes aye.
1493 Mr. Landsman?
1494 *Mr. Landsman. Aye.
1495 *The Clerk. Mr. Landsman votes aye.
1496 Ms. McClellan?
1497 *Ms. McClellan. Aye.
1498 *The Clerk. Ms. McClellan votes aye.
1499 Mr. Guthrie?

1500 *The Chair. Aye.

1501 *The Clerk. Mr. Guthrie votes aye.

1502 *Mr. Pfluger. Aye.

1503 *The Clerk. Mr. Pfluger votes aye.

1504 *The Clerk. Mrs. Cammack is not recorded.

1505 *Mrs. Cammack. Cammack votes aye.

1506 *The Clerk. Mrs. Cammack votes aye.

1507 *Mr. James. How is James recorded?

1508 *The Clerk. Mr. James is not recorded.

1509 *Mr. James. James is aye.

1510 *The Clerk. Mr. James votes aye.

1511 *The Chair. Crenshaw?

1512 *The Clerk. Mr. Crenshaw is not recorded.

1513 *Mr. Crenshaw. Votes aye.

1514 *The Clerk. Mr. Crenshaw votes aye.

1515 *The Chair. Harshbarger?

1516 *The Clerk. Mrs. Harshbarger is not recorded.

1517 *Mrs. Harshbarger. Aye.

1518 *The Clerk. Mrs. Harshbarger votes aye.

1519 *The Chair. Mr. Ruiz?

1520 *The Clerk. Mr. Ruiz is not recorded.

1521 *Mr. Ruiz. Aye.

1522 *The Clerk. Mr. Ruiz votes aye.

1523 *The Chair. Veasey?

1524 *The Clerk. Mr. Veasey is not recorded.

1525 *Mr. Veasey. Aye.

1526 *The Clerk. Mr. Veasey votes aye.

1527 *The Chair. Is anybody else seeking recognition to
1528 answer the roll call?

1529 Seeing none, the clerk will call the roll -- the clerk
1530 will report, I am sorry.

1531 *The Clerk. Mr. Chairman, on that vote there were 52
1532 ayes and 0 noes.

1533 *The Chair. With 52 ayes and 0 nays, the bill is
1534 adopted.

1535 The chair calls up H.R. 6633, and asks the clerk to
1536 report.

1537 *The Clerk. Committee print of H.R. 6633, a bill to
1538 establish --

1539 *The Chair. Without objection, the first reading of the
1540 bill is dispensed with, and the bill will be open for
1541 amendment at any point.

1542 So ordered.

1543 [The bill follows:]

1544

1545 *****COMMITTEE INSERT*****

1546

1547 *The Chair. Does anyone seek recognition to speak on
1548 the bill?

1549 For what purpose does the gentlelady from North Dakota
1550 seek recognition?

1551 You are recognized for five minutes to speak on the
1552 bill. I am sorry.

1553 *Mrs. Fedorchak. Thank you, Mr. Chairman, Ranking
1554 Member, and subcommittee staff. Thank you for working with
1555 me to include this legislation, the High-Capacity Grid Act,
1556 in this markup.

1557 The High-Capacity Grid Act is a common-sense solution to
1558 modernize America's aging electric grid with new, innovative
1559 technologies. This bill will increase capacity, reduce
1560 costs, and foster a new age of energy affordability for
1561 American families.

1562 Members of this Congress, including those in this
1563 committee, often cite the sudden rise in demand due to
1564 electrification, large loads, and onshoring manufacturing
1565 across the country. At the same time, permitting backlogs
1566 prevent us from building new transmission lines, the lines we
1567 need to meet this demand. On average, it takes more than
1568 four years to -- just to permit a new transmission line, and
1569 sometimes more than a decade. This is before a single shovel
1570 hits the ground. We simply can't afford to wait that long.

1571 According to the Department of Energy, over 70 percent

1572 of our transmission lines are more than 25 years old. They
1573 are still relying on outdated, inefficient technologies.
1574 This directly leads to power outages and capacity
1575 limitations, driving up costs for the families that we
1576 represent. To fix this we should make use of the valuable
1577 infrastructure we already have. Meeting growing demand means
1578 increasing capacity and efficiency across our grid.
1579 Innovative technologies like advanced conductors can maximize
1580 the value of infrastructure, the infrastructure we already
1581 have in the ground. This sets our grid up for long-term
1582 success without waiting years for new lines to be permitted
1583 or built. That is why my bill, the High-Capacity Grid Act,
1584 is important.

1585 Under the bill, utilities replacing or constructing new
1586 transmission lines would deploy the most efficient, highest
1587 capacity, and most cost-effective conductors available. This
1588 reduces outages, optimizes existing infrastructure, and
1589 supports increasing demand in a pragmatic manner. The
1590 result? Lower costs and greater reliability for American
1591 families.

1592 I would like to thank the chairman and ranking member
1593 again, and urge my colleagues to support the High-Capacity
1594 Grid Act.

1595 And I yield back.

1596 *The Chair. The gentlelady yields back. Is there

1597 discussion on the bill, further discussion on the bill?

1598 Seeing none, are there any amendments to the bill?

1599 *Mrs. Fedorchak. Yes.

1600 *The Chair. For what purpose does the gentlelady from
1601 North Dakota have -- seek recognition?

1602 *Mrs. Fedorchak. I would like to offer an amendment to
1603 H.R. 6633, Mr. Chairman.

1604 *The Chair. Identify the amendment at the desk and the
1605 clerk will -- do you have the amendment? The clerk can
1606 report.

1607 *The Clerk. Amendment to the committee print for H.R.
1608 6633 offered by --

1609 *The Chair. Without objection, the reading of the
1610 amendment is dispensed with, and the gentlelady is recognized
1611 for five minutes in support of the amendment.

1612 *Mrs. Fedorchak. Thank you, Chairman Guthrie. I am
1613 pleased to offer an amendment to my bill, the High-Capacity
1614 Grid Act, that will address concerns from both sides of the
1615 aisle.

1616 The amendment modifies the bill to provide exemptions
1617 when the use of advanced conductors would be unsafe for
1618 American families or for the electric grid. Furthermore, it
1619 provides utilities flexibility during reconductoring or new
1620 construction when advanced conductors are cost prohibitive or
1621 unnecessary to increase the system capacity or efficiency.

1622 While advanced conductors can increase capacity and
1623 efficiency across the grid, they are not always necessary.
1624 This amendment recognizes that reality. In doing so it
1625 provides the experts enough flexibility to build today's grid
1626 to meet tomorrow's need while protecting American families
1627 and affordability.

1628 I thank Chairman Guthrie and the committee staff for
1629 their work on this bill and the amendment, and I urge my
1630 colleagues to support it.

1631 And I yield back.

1632 *The Chair. Is there further discussion? The
1633 gentlelady yields back. Is there further discussion on the
1634 amendment?

1635 Seeing none, are there further amendments?

1636 Yes, that is right. So if there is no further
1637 discussion, the vote occurs on the amendment offered by the
1638 gentlelady from North Dakota.

1639 All those in favor shall signify by saying aye.

1640 All opposed, say nay.

1641 The ayes have it and the amendment is agreed to. Are
1642 there any further amendments to the bill?

1643 Seeing none, the question now occurs on adopting H.R.
1644 633 (sic), as amended. A roll call has been requested, and
1645 the clerk will call the roll.

1646 *The Clerk. Mr. Latta?

1647 *Mr. Latta. Aye.
1648 *The Clerk. Mr. Latta votes aye.
1649 Mr. Griffith?
1650 *Mr. Griffith. Aye.
1651 *The Clerk. Mr. Griffith votes aye.
1652 Mr. Bilirakis?
1653 *Mr. Bilirakis. Aye.
1654 *The Clerk. Mr. Bilirakis votes aye.
1655 Mr. Hudson?
1656 [No response.]
1657 *The Clerk. Mr. Carter of Georgia?
1658 [No response.]
1659 *The Clerk. Mr. Palmer?
1660 [No response.]
1661 *The Clerk. Mr. Dunn?
1662 [No response.]
1663 *Mr. Palmer. Aye.
1664 *The Clerk. Mr. Palmer votes aye.
1665 Mr. Dunn?
1666 [No response.]
1667 *The Clerk. Mr. Crenshaw?
1668 [No response.]
1669 *The Clerk. Mr. Joyce?
1670 *Mr. Joyce. Aye.
1671 *The Clerk. Mr. Joyce votes aye.

1672 Mr. Weber?
1673 *Mr. Weber. Aye.
1674 *The Clerk. Mr. Weber votes aye.
1675 Mr. Allen?
1676 *Mr. Allen. Aye.
1677 *The Clerk. Mr. Allen votes aye.
1678 Mr. Balderson?
1679 [No response.]
1680 *The Clerk. Mr. Fulcher?
1681 *Mr. Fulcher. Fulcher is aye.
1682 *The Clerk. Mr. Fulcher votes aye.
1683 Mr. Pfluger?
1684 *Mr. Pfluger. Aye.
1685 *The Clerk. Mr. Pfluger votes aye.
1686 Mrs. Harshbarger?
1687 [No response.]
1688 *The Clerk. Mrs. Harshbarger?
1689 *Mrs. Harshbarger. Aye.
1690 *The Clerk. Mrs. Harshbarger votes aye.
1691 Mrs. Miller-Meeks?
1692 [No response.]
1693 *The Clerk. Mrs. Cammack?
1694 [No response.]
1695 *The Clerk. Mr. Obernolte?
1696 [No response.]

1697 *The Clerk. Mr. James?
1698 *Mr. James. Aye.
1699 *The Clerk. Mr. James votes aye.
1700 Mr. Bentz?
1701 *Mr. Bentz. Aye.
1702 *The Clerk. Mr. Bentz votes aye.
1703 Mrs. Houchin?
1704 *Mrs. Houchin. Aye.
1705 *The Clerk. Mrs. Houchin votes aye.
1706 Mr. Fry?
1707 *Mr. Fry. Aye.
1708 *The Clerk. Mr. Fry votes aye.
1709 Ms. Lee?
1710 *Ms. Lee. Aye.
1711 *The Clerk. Ms. Lee votes aye.
1712 Mr. Langworthy?
1713 *Mr. Langworthy. Aye.
1714 *The Clerk. Mr. Langworthy votes aye.
1715 Mr. Kean?
1716 *Mr. Kean. Aye.
1717 *The Clerk. Mr. Kean votes aye.
1718 Mr. Rulli?
1719 *Mr. Rulli. Aye.
1720 *The Clerk. Mr. Rulli votes aye.
1721 Mr. Evans?

1722 *Mr. Evans. Aye.
1723 *The Clerk. Mr. Evans votes aye.
1724 Mr. Goldman?
1725 *Mr. Goldman. Aye.
1726 *The Clerk. Mr. Goldman votes aye.
1727 Mrs. Fedorchak?
1728 *Mrs. Fedorchak. Aye.
1729 *The Clerk. Mrs. Fedorchak votes aye.
1730 Mr. Pallone?
1731 *Mr. Pallone. Aye.
1732 *The Clerk. Mr. Pallone votes aye.
1733 Ms. DeGette?
1734 *Ms. DeGette. Aye.
1735 *The Clerk. Ms. DeGette votes aye.
1736 Ms. Schakowsky?
1737 *Ms. Schakowsky. Aye.
1738 *The Clerk. Ms. Schakowsky votes aye.
1739 Ms. Matsui?
1740 *Ms. Matsui. Aye.
1741 *The Clerk. Ms. Matsui votes aye.
1742 Ms. Castor?
1743 *Ms. Castor. Aye.
1744 *The Clerk. Ms. Castor votes aye.
1745 Mr. Tonko?
1746 *Mr. Tonko. Aye.

1747 *The Clerk. Mr. Tonko votes aye.
1748 Ms. Clarke?
1749 *Ms. Clarke. Aye.
1750 *The Clerk. Ms. Clarke votes aye.
1751 Mr. Ruiz?
1752 [No response.]
1753 *The Clerk. Mr. Peters?
1754 *Mr. Peters. Aye.
1755 *The Clerk. Mr. Peters votes aye.
1756 Mrs. Dingell?
1757 *Mrs. Dingell. Aye.
1758 *The Clerk. Mrs. Dingell votes aye.
1759 Mr. Veasey?
1760 *Mr. Veasey. Aye.
1761 *The Clerk. Mr. Veasey votes aye.
1762 Ms. Kelly?
1763 [No response.]
1764 *The Clerk. Ms. Barragan?
1765 *Ms. Barragan. Aye.
1766 *The Clerk. Ms. Barragan votes aye.
1767 Mr. Soto?
1768 *Mr. Soto. Aye.
1769 *The Clerk. Mr. Soto votes aye.
1770 Ms. Schrier?
1771 *Ms. Schrier. Aye.

1772 *The Clerk. Ms. Schrier votes aye.
1773 Mrs. Trahan?
1774 *Mrs. Trahan. Aye.
1775 *The Clerk. Mrs. Trahan votes aye.
1776 Mrs. Fletcher?
1777 *Mrs. Fletcher. Aye.
1778 *The Clerk. Mrs. Fletcher votes aye.
1779 Ms. Ocasio-Cortez?
1780 *Ms. Ocasio-Cortez. Aye.
1781 *The Clerk. Ms. Ocasio-Cortez votes aye.
1782 Mr. Auchincloss?
1783 *Mr. Auchincloss. Aye.
1784 *The Clerk. Mr. Auchincloss votes aye.
1785 Mr. Carter of Louisiana?
1786 *Mr. Carter of Louisiana. Aye.
1787 *The Clerk. Mr. Carter of Louisiana votes aye.
1788 Mr. Menendez?
1789 *Mr. Menendez. Aye.
1790 *The Clerk. Mr. Menendez votes aye.
1791 Mr. Mullin?
1792 *Mr. Mullin. Aye.
1793 *The Clerk. Mr. Mullin votes aye.
1794 Mr. Landsman?
1795 *Mr. Landsman. Aye.
1796 *The Clerk. Mr. Landsman votes aye.

1797 Ms. McClellan?
1798 *Ms. McClellan. Aye.
1799 *The Clerk. Ms. McClellan votes aye.
1800 Chairman Guthrie?
1801 *The Chair. Aye.
1802 *The Clerk. Chairman Guthrie votes aye.
1803 *The Chair. So I can call out your name and just vote.
1804 So we got Mrs. Miller-Meeks.
1805 *Mrs. Miller-Meeks. Aye.
1806 *The Clerk. Mrs. Miller-Meeks votes --
1807 *The Chair. Mr. Carter?
1808 *Mr. Carter of Georgia. Aye.
1809 *The Clerk. Mr. Carter votes aye.
1810 *The Chair. Mr. Balderson?
1811 *Mr. Balderson. Aye.
1812 *The Clerk. Mr. Balderson votes aye.
1813 *The Chair. Okay. Mr. -- Dr. Ruiz?
1814 *Mr. Ruiz. Aye.
1815 *The Clerk. Mr. Ruiz votes aye.
1816 *The Chair. Ms. Kelly?
1817 *Ms. Kelly. Aye.
1818 *The Clerk. Ms. Kelly votes aye.
1819 *The Chair. I almost said Ms. Robin.
1820 Seeing no further people here to answer the roll call,
1821 the clerk will report.

1822 [Pause.]

1823 *The Clerk. Mr. Chairman, on that vote there were 49
1824 ayes and 0 noes.

1825 *The Chair. The ayes have it, and the bill is adopted.
1826 The chair calls up H.R. 9335 and asks the clerk to
1827 report.

1828 *The Clerk. H.R. 9335, a bill to direct the Secretary
1829 of Energy to establish a clearing --

1830 *The Chair. Without objection, the first reading of the
1831 bill is dispensed with, and the bill will be open for
1832 amendment at any point.

1833 So ordered.

1834 [The bill follows:]

1835

1836 *****COMMITTEE INSERT*****

1837

1838 *The Chair. Does anyone seek to be recognized on the
1839 bill?

1840 The gentleman from Texas is recognized to speak on the
1841 bill.

1842 *Mr. Goldman. Thank you, Mr. Chairman.

1843 Grid congestion is a hidden tax on every American family
1844 and business. My bipartisan bill, the Advanced Transmission
1845 Technology to Reduce Rates Act, cuts that tax by making our
1846 electric grid smarter and more efficient without mandates,
1847 without Federal overreach, and without waiting on Washington.

1848 Texas is growing fast, and our grid is being asked to do
1849 more than ever. In fact, yesterday it is estimated that it
1850 hit its all-time capacity record. Congestion drives up the
1851 cost of energy for utilities, and ultimately for ratepayers.
1852 My bill addresses that head on by expanding access to
1853 advanced transmission technologies, tools like advanced
1854 conductors and dynamic line ratings that move more
1855 electricity across the lines we already have.

1856 It is a common-sense, three-part bill, a public DoE
1857 clearinghouse on advanced transmission projects, voluntary
1858 technical assistance for utilities and state regulators, and
1859 voluntary best practices to reduce wildlife -- wildfire risk,
1860 and it targets NEPA review for these specific, DoE-funded
1861 projects so states like Texas aren't stuck waiting on a
1862 lengthy Federal process to deploy technology that already

1863 works.

1864 This bipartisan bill builds on the permitting reform
1865 work House Republicans have led all Congress to cut the red
1866 tape standing between American families and a more reliable,
1867 more affordable grid. I urge my colleagues to support this
1868 legislation.

1869 I thank the chair and I yield back.

1870 *Mr. Latta. [Presiding.] Thank you very much. The
1871 gentleman yields back. The chair now recognizes the
1872 gentleman from New Jersey, the ranking member of the full
1873 committee, for five minutes.

1874 *Mr. Pallone. Thank you, Chairman Latta. I strongly
1875 support this bill, but I do have an issue with one provision,
1876 and that provision would exclude any Department of Energy
1877 funding for advanced transmission technologies from the
1878 environmental review requirements of the National
1879 Environmental Policy Act, or NEPA.

1880 And my problem is that -- a concerted Republican attack
1881 on our environmental review laws like last year's radical
1882 Republican proposal to completely upend our nation's
1883 environmental reviews. Thankfully, this bill does not go
1884 that far, and NEPA would still apply for any projects that
1885 incorporate broader work that goes beyond advanced
1886 transmission technologies.

1887 DoE regulations already exempt activities relating to

1888 upgrading or rebuilding existing electric power lines from
1889 NEPA, and any project requiring a Federal permit would still
1890 be subject to environmental reviews, just not for the funding
1891 it received from the Department of Energy.

1892 I am frustrated because this provision is simply
1893 unnecessary in an otherwise worthwhile bill. As Democrats
1894 have noted for years, we desperately need to expand our grid
1895 to help make it more reliable and affordable in the face of
1896 increasing electricity demand, and advanced transmission
1897 technologies are a key component of that grid expansion and
1898 have the potential to help us get some of the biggest bang
1899 for our buck.

1900 So because I strongly support advanced transmission
1901 technologies and the benefits they bring to the grid, I will
1902 support the bill today.

1903 And thank you, Mr. Chairman. I yield back.

1904 *Mr. Latta. Thank you very much. The gentleman yields
1905 back. Is there any further discussion on the bill?

1906 Hearing none, are there any amendments on the bill?

1907 The question now occurs on adopting H.R. 9335. A roll
1908 call has been requested, and the clerk will call the roll.

1909 *The Clerk. Mr. Latta?

1910 *Mr. Latta. Aye.

1911 *The Clerk. Mr. Latta votes aye.

1912 Mr. Griffith?

1913 *Mr. Griffith. Aye.
1914 *The Clerk. Mr. Griffith votes aye.
1915 Mr. Bilirakis?
1916 [No response.]
1917 *The Clerk. Mr. Bilirakis?
1918 *Mr. Bilirakis. Aye.
1919 *The Clerk. Mr. Bilirakis votes aye.
1920 Mr. Hudson?
1921 [No response.]
1922 *The Clerk. Mr. Carter of Georgia?
1923 *Mr. Carter of Georgia. Aye.
1924 *The Clerk. Mr. Carter of Georgia votes aye.
1925 Mr. Palmer?
1926 [No response.]
1927 *The Clerk. Mr. Dunn?
1928 [No response.]
1929 *The Clerk. Mr. Crenshaw?
1930 [No response.]
1931 *The Clerk. Mr. Joyce?
1932 *Mr. Joyce. Aye.
1933 *The Clerk. Mr. Joyce votes aye.
1934 Mr. Weber?
1935 [No response.]
1936 *The Clerk. Mr. Allen?
1937 *Mr. Allen. Aye.

1938 *The Clerk. Mr. Allen votes aye.
1939 Mr. Balderson?
1940 *Mr. Balderson. Aye.
1941 *The Clerk. Mr. Balderson votes aye.
1942 Mr. Fulcher?
1943 *Mr. Fulcher. Fulcher is aye.
1944 *The Clerk. Mr. Fulcher votes aye.
1945 *Mr. Pfluger. Aye.
1946 *The Clerk. Mr. Pfluger votes aye.
1947 Mrs. Harshbarger?
1948 [No response.]
1949 *The Clerk. Mrs. Miller-Meeks?
1950 *Mrs. Miller-Meeks. Aye.
1951 *The Clerk. Mrs. Miller-Meeks votes aye.
1952 Mrs. Cammack?
1953 [No response.]
1954 *The Clerk. Mr. Obernolte?
1955 [No response.]
1956 *The Clerk. Mr. James?
1957 *Mr. James. Aye.
1958 *The Clerk. Mr. James votes aye.
1959 Mr. Bentz?
1960 *Mr. Bentz. Aye.
1961 *The Clerk. Mr. Bentz votes aye.
1962 Mrs. Houchin?

1963 *Mrs. Houchin. Aye.
1964 *The Clerk. Mrs. Houchin votes aye.
1965 Mr. Fry?
1966 *Mr. Fry. Aye.
1967 *The Clerk. Mr. Fry votes aye.
1968 Ms. Lee?
1969 *Ms. Lee. Aye.
1970 *The Clerk. Ms. Lee votes aye.
1971 Mr. Langworthy?
1972 *Mr. Langworthy. Aye.
1973 *The Clerk. Mr. Langworthy votes aye.
1974 Mr. Kean?
1975 *Mr. Kean. Aye.
1976 *The Clerk. Mr. Kean votes aye.
1977 Mr. Rulli?
1978 *Mr. Rulli. Aye.
1979 *The Clerk. Mr. Rulli votes aye.
1980 Mr. Evans?
1981 *Mr. Evans. Aye.
1982 *The Clerk. Mr. Evans votes aye.
1983 Mr. Goldman?
1984 *Mr. Goldman. Aye.
1985 *The Clerk. Mr. Goldman votes aye.
1986 Mrs. Fedorchak?
1987 [No response.]

1988 *The Clerk. Mr. Pallone?
1989 *Mr. Pallone. Aye.
1990 *The Clerk. Mr. Pallone votes aye.
1991 Ms. DeGette?
1992 *Ms. DeGette. Aye.
1993 *The Clerk. Ms. DeGette votes aye.
1994 Ms. Schakowsky?
1995 *Ms. Schakowsky. Aye.
1996 *The Clerk. Ms. Schakowsky votes aye.
1997 Ms. Matsui?
1998 *Ms. Matsui. No.
1999 *The Clerk. Ms. Matsui votes no.
2000 Ms. Castor?
2001 *Ms. Castor. No.
2002 *The Clerk. Ms. Castor votes no.
2003 Mr. Tonko?
2004 *Mr. Tonko. No.
2005 *The Clerk. Mr. Tonko votes no.
2006 Ms. Clarke?
2007 *Ms. Clarke. No.
2008 *The Clerk. Ms. Clarke votes no.
2009 Mr. Ruiz?
2010 *Mr. Ruiz. No.
2011 *The Clerk. Mr. Ruiz votes no.
2012 Mr. Peters?

2013 *Mr. Peters. Aye.

2014 *The Clerk. Mr. Peters votes aye.

2015 Mrs. Dingell?

2016 *Mrs. Dingell. Aye.

2017 *The Clerk. Mrs. Dingell votes aye.

2018 Mr. Veasey?

2019 *Mr. Veasey. Aye.

2020 *The Clerk. Mr. Veasey votes aye.

2021 Ms. Kelly?

2022 *Ms. Kelly. Aye.

2023 *The Clerk. Ms. Kelly votes aye.

2024 Ms. Barragan?

2025 *Ms. Barragan. No.

2026 *The Clerk. Ms. Barragan votes no.

2027 Mr. Soto?

2028 *Mr. Soto. Aye.

2029 *The Clerk. Mr. Soto votes aye.

2030 Ms. Schrier?

2031 *Ms. Schrier. Aye.

2032 *The Clerk. Ms. Schrier votes aye.

2033 Mrs. Trahan?

2034 *Mrs. Trahan. Aye.

2035 *The Clerk. Mrs. Trahan votes aye.

2036 Mrs. Fletcher?

2037 *Mrs. Fletcher. Aye.

2038 *The Clerk. Mrs. Fletcher votes aye.
2039 Ms. Ocasio-Cortez?
2040 *Ms. Ocasio-Cortez. No.
2041 *The Clerk. Ms. Ocasio-Cortez votes no.
2042 Mr. Auchincloss?
2043 *Mr. Auchincloss. No.
2044 *The Clerk. Mr. Auchincloss votes no.
2045 Mr. Carter of Louisiana?
2046 *Mr. Carter of Louisiana. Aye.
2047 *The Clerk. Mr. Carter of Louisiana votes aye.
2048 Mr. Menendez?
2049 *Mr. Menendez. Aye.
2050 *The Clerk. Mr. Menendez votes aye.
2051 Mr. Mullin?
2052 *Mr. Mullin. Aye.
2053 *The Clerk. Mr. Mullin votes aye.
2054 Mr. Landsman?
2055 *Mr. Landsman. Aye.
2056 *The Clerk. Mr. Landsman votes aye.
2057 Ms. McClellan?
2058 *Ms. McClellan. No.
2059 *The Clerk. Ms. McClellan votes no.
2060 Chairman Guthrie?
2061 *The Chair. Aye.
2062 *The Clerk. Chairman Guthrie votes aye.

2063 *The Chair. [Presiding.] Is anyone -- the gentleman
2064 from Alabama, Mr. Palmer?
2065 *The Clerk. Mr. Palmer is not recorded.
2066 *Mr. Palmer. Palmer votes aye.
2067 *The Clerk. Mr. Palmer votes aye.
2068 *The Chair. I will call, and you can just do your vote
2069 when I call.
2070 So Mrs. Harshbarger? Aye?
2071 *The Clerk. Mrs. Harshbarger is not recorded.
2072 *Mrs. Harshbarger. Aye.
2073 *The Clerk. Mrs. Harshbarger votes aye.
2074 *The Chair. Mr. Crenshaw?
2075 *Mr. Crenshaw. Aye.
2076 *The Clerk. Mr. Crenshaw votes aye.
2077 *The Chair. Mr. Weber?
2078 *Mr. Weber. Aye.
2079 *The Clerk. Mr. Weber votes aye.
2080 *The Chair. Mr. Auchincloss?
2081 *Mr. Auchincloss. I would like to change my vote to
2082 aye.
2083 *The Chair. Ms. Kelly?
2084 *The Clerk. Mr. Auchincloss is off no and on aye.
2085 *The Chair. Okay. Ms. Kelly?
2086 [Pause.]
2087 *Ms. Kelly. No.

2088 *The Chair. Did you get Ms. Kelly's vote?

2089 *Ms. Kelly. Ms. Kelly is off aye and on no.

2090 *The Chair. Okay. Ms. DeGette?

2091 *Ms. DeGette. I am also going to go off aye, on no.

2092 *The Clerk. Ms. DeGette is off aye and on no.

2093 *The Chair. Anyone else? Is anyone seeking to answer
2094 the roll call?

2095 The gentleman will report. The clerk will report.

2096 [Pause.]

2097 *The Clerk. Mr. Chairman, on that vote there were 39
2098 ayes and 10 noes.

2099 *The Chair. The ayes have it, and the bill is adopted.

2100 The chair calls up H.R. 9338 and asks the clerk to
2101 report.

2102 *The Clerk. H.R. 9338, a bill to amend title --

2103 *The Chair. Without objection, the first reading of the
2104 bill is dispensed with, and the bill will be open for
2105 amendment at any point.

2106 So ordered.

2107 [The bill follows:]

2108

2109 *****COMMITTEE INSERT*****

2110

2111 *The Chair. Does anyone seek to be recognized on the
2112 bill?

2113 Mr. Weber is recognized -- what -- for five minutes to
2114 speak on the bill.

2115 *Mr. Weber. Thank you, Mr. Chairman. I have an
2116 amendment in the nature of a substitute at the desk.

2117 *The Chair. The gentleman -- does anybody want to speak
2118 on the bill before we bring up -- or just -- do you want to
2119 speak on the bill or the substitute?

2120 The gentleman -- is there anyone speaking on the bill
2121 before we bring up an amendment?

2122 *Mr. Weber. I will take that. Thank you, Mr. Chairman.

2123 This ANS before us today reflects important updates made
2124 since the Energy Subcommittee markup last month. These
2125 changes fulfill the commitments we made during that markup to
2126 keep working across the aisle toward a strong bipartisan
2127 final product. We listened, we kept our word, and we
2128 tightened the language to protect the First Amendment rights
2129 of lawful protesters while holding those accountable who
2130 knowingly and willfully damage pipeline equipment or disrupt
2131 operations by manipulating a valve.

2132 Throughout this process we have worked closely with
2133 stakeholders across the industry, within the government. We
2134 have worked to develop and refine this legislation. The
2135 result is a stronger bill that gives the Pipeline and

2136 Hazardous Materials Safety Administration, PHMSA, the
2137 resources and direction necessary to continue safeguarding
2138 more than three million miles of pipeline infrastructure
2139 across these great United States.

2140 The bill strengthens the civil penalties for pipeline
2141 safety violations. The bill promotes best practices across
2142 state damage prevention programs, and the bill establishes a
2143 voluntary information-sharing system so lessons learned from
2144 accidents and near misses can help prevent the next one. It
2145 also supports communities working to repair and replace aging
2146 natural gas distribution systems. It sets deadlines for
2147 updated carbon dioxide pipeline safety standards and requires
2148 PHMSA to lay out a plan for completing overdue pipeline
2149 safety rulemakings.

2150 Americans deserve nothing less than our continued effort
2151 to move the needle closer and closer and closer to 100
2152 percent safety, and this legislation actually helps to do
2153 exactly that. Our nation's pipeline infrastructure operates
2154 24 hours a day, 7 days a week to safely deliver the reliable
2155 and affordable energy that power Americans' homes, their
2156 businesses, and industries while supporting our allies around
2157 the world.

2158 Few regions in the country can rival the pipeline
2159 infrastructure along the Texas Gulf Coast, where I represent.
2160 Every day that infrastructure helps produce, refine, process,

2161 and export the energy that powers America, and as well as
2162 supports our allies abroad. In Texas's 14th congressional
2163 district we produce and move more energy than just about any
2164 other district in these good old United States of America.

2165 Few places better illustrate the important role pipeline
2166 infrastructure plays in our everyday lives, whether that
2167 energy originates in the Permian Basin or comes from our
2168 neighbors to the north -- Alberta, Canada -- producing it is
2169 only half of the battle. American energy dominance depends
2170 on our ability to deliver that very energy safely and
2171 reliably to the people, businesses, and industries that, yes,
2172 depend on it every single day.

2173 Mr. Chairman, this bill reflects what dedicated members
2174 of this body and their staff can accomplish when we all come
2175 together to the table to help make America better. I want to
2176 thank them for their hard work, and I urge every member of
2177 this committee to support H.R. 9338 and help move this strong
2178 bipartisan bill one step closer to the House floor.

2179 Mr. Chairman, I yield back the balance of my time.

2180 *The Chair. The gentleman yields back. Is there
2181 further discussion on the bill?

2182 The gentleman from New Jersey is recognized for five
2183 minutes to speak on the bill.

2184 *Mr. Pallone. Thank you, Mr. Chairman, but I think both
2185 the gentleman from Texas and I are actually talking about the

2186 bill with the changes that are going to be in the ANS, but I
2187 will follow up on what he said. If we do the bill as
2188 amended, we will have made sufficient progress for me to
2189 support the underlying bill.

2190 One of our most important responsibilities as Members of
2191 Congress is to do what we can to protect our constituents.
2192 In the case of pipeline safety legislation, that means
2193 ensuring that the Pipeline and Hazardous Materials Safety
2194 Administration, or PHMSA, has the resources it needs to hold
2195 unsafe pipeline operators responsible. It also means
2196 ensuring that those operators are assessed fines that
2197 actually hold them financially accountable, rather than
2198 amounting to a slap on the wrist.

2199 Two years ago the bill the majority drafted failed that
2200 test, and so did the bill that was introduced and marked up
2201 by the Energy Subcommittee just last month. But with the
2202 changes, I believe this bill will live up to that obligation,
2203 and I want to detail why.

2204 The first reason is that it gives PHMSA the resources it
2205 needs to enforce its safety rules and ensure that pipeline
2206 operators are abiding by those rules. The core authorization
2207 levels in this bill are roughly \$24 million per year higher
2208 than the levels contained in the introduced bill. That
2209 increase will support vital programs like the State Damage
2210 Prevention Program and pipeline safety information grants to

2211 communities. It will also ensure that PHMSA's primary
2212 enforcement and operation activities get the resources they
2213 deserve, and these levels are essentially identical to the
2214 funding levels put forward by the Transportation Committee
2215 and the Senate Commerce Committee, and they live up to the
2216 nation's pipeline safety needs.

2217 Additionally, this bill fully authorizes a grant program
2218 originally funded in the Bipartisan Infrastructure Law. The
2219 Natural Gas Distribution, Infrastructure Safety, and
2220 Modernization Grant program helps repair leaky distribution
2221 pipelines operated by municipal utilities and cooperatives.
2222 In an era of ever-increasing energy costs driven by President
2223 Trump's disastrous policies, a grant program that helps lower
2224 utility costs by helping ratepayer-owned utilities make
2225 investments, essentially to bring down the cost, is vital.
2226 And the majority's original bill would have let this program
2227 expire, and I am pleased that our compromise amendment today
2228 lets it survive and sets it up for sustainability into the
2229 future.

2230 Finally, the majority's original bill contained language
2231 that would have made it a crime "to impair the operation of a
2232 pipeline'', while leaving that term undefined. At a time
2233 when former Olympians are being arrested on the National Mall
2234 for the crime of looking at the damage the President dealt to
2235 the Reflecting Pool, granting DoJ authority to prosecute

2236 everyday Americans for exercising their First Amendment
2237 rights was completely unacceptable. This compromise
2238 amendment protects the First Amendment by ensuring that only
2239 valve-turning and intentionally causing a defect in the
2240 pipeline is criminalized. With this change, only activities
2241 that present a danger to the safety of others are out of
2242 bounds, and Americans' right to protest and exercise their
2243 free speech remains intact, in my opinion.

2244 And there are other important changes contained in this
2245 amendment protecting PHMSA's consideration of environmental
2246 benefits, instructing PHMSA to finalize the rule regulating
2247 the safety of carbon dioxide pipelines, for example. All
2248 these changes combine to make this a stronger pipeline safety
2249 package, and for that reason I support the amendment and the
2250 bill as amended.

2251 I hope we can continue to improve the bill in
2252 discussions with our colleagues on the House --

2253 *Mr. Weber. Will the gentleman yield back?

2254 *Mr. Pallone. Yes, let me just finish, though.

2255 You know, I know we still have to work with our
2256 colleagues on the House Transportation and the Senate
2257 Commerce Committee -- dare I mention the Senate Commerce
2258 Committee's name -- and that the final product that is signed
2259 into law, I think, will be even better.

2260 So I yield. Do you want me to yield to you?

2261 *Mr. Weber. I do.

2262 *Mr. Pallone. Sure.

2263 *Mr. Weber. I thank the ranking member, Mr. Chairman.
2264 And before I yield back to him I am going to mention this is
2265 an ANS_HR9338_01. So we appreciate that, we appreciate your
2266 position on this, Ranking Member.

2267 Mr. Chairman, I yield back.

2268 *Mr. Pallone. Thank you.

2269 *The Chair. Can you yield to me, as well?

2270 *Mr. Pallone. Sure.

2271 *The Chair. I just want to say -- and I think the
2272 gentlelady from New York had pointed out -- the issue you
2273 just addressed, and how we all worked together. We withdrew
2274 the amendment on good faith that we would work together, and
2275 thanks for everybody. That doesn't always mean we are going
2276 to get there. We did this time. But we certainly did it in
2277 good faith.

2278 So again, another point to the -- why we have so many
2279 bills today, because we are all working to get these things
2280 done for the American people.

2281 So thank you and I yield back.

2282 *Mr. Pallone. Thank you, Mr. Chairman. I support the
2283 bill, as amended, and yield back the balance of my time.

2284 *The Chair. Is there further discussion on the bill?
2285 The gentleman from -- on the bill, or do you want to

2286 wait for the ANS to be adopted or brought forward?

2287 Do you want to call up the amendment, or do you want
2288 first --

2289 *Mr. Mullin. On the bill, Mr. --

2290 *The Chair. Okay, the gentleman from -- well, Mrs.
2291 Fletcher from Texas, do you want to -- so the gentlelady from
2292 Texas is recognized to speak on the bill.

2293 *Mrs. Fletcher. Well, thank you so much, Chairman
2294 Guthrie. This bill is so important to the people that I
2295 represent, and I am so glad that we have made changes in
2296 progress since the subcommittee markup, as you were just
2297 discussing.

2298 I think everyone in here has heard me say this before,
2299 and certainly Mr. Weber and my colleagues from Houston know
2300 that Houston companies control more than 58 percent of U.S.
2301 natural gas pipeline capacity and 33 percent of U.S. crude
2302 oil pipeline capacity and oil pipeline capacity. So, you
2303 know, the people that I represent know that pipeline safety
2304 is paramount, and that it must remain a priority as the
2305 demand for energy grows, which we keep talking about on this
2306 committee, and as the demand for infrastructure to deliver
2307 that continues to grow as well. And we know that that is
2308 PHMSA's job. It is in the name of the agency.

2309 And so I am just really glad that we have come together
2310 as a committee to advance a bipartisan reauthorization of

2311 PHMSA, and it really plays a vital role in working to keep
2312 our communities safe, in working with industry, overseeing
2313 industry as appropriate, but working to make sure that it can
2314 accomplish its mission. But we know that, like so many other
2315 agencies, it has faced a lot of challenges from the Trump
2316 Administration.

2317 And since the beginning of this Administration, more
2318 than half of PHMSA's senior leadership has left several
2319 rulemakings -- major rulemakings have been abandoned, and
2320 this is a problem for everyone. It is a problem for our
2321 communities, it is a problem for the people who are trying to
2322 build and operate the pipelines safely. And so we address a
2323 lot of the challenges that they are experiencing in this
2324 bill, and I think that that is really important.

2325 I think that, you know, this bill is going to provide
2326 \$90 million a year more than the original authorization for
2327 PHMSA for pipeline safety activities, and I hope that those
2328 resources are directed toward retaining staff because that is
2329 a critical issue right now.

2330 The bill also compels PHMSA to release a rule regulating
2331 carbon dioxide pipelines within two years of enactment, and
2332 it requires PHMSA to update Congress on the status of these
2333 outstanding rulemakings that have been abandoned. And this
2334 is critically important because we did a lot of good work in
2335 the last couple of Congresses to try to advance different

2336 programs and policies and technologies. And we are waiting
2337 on rulemakings, like with the carbon dioxide pipelines that
2338 are impeding our ability to achieve our climate goals, that
2339 are impeding our ability to make the progress that we all
2340 should want to make.

2341 And we know in Texas, of course, as carbon capture
2342 projects advance it is really vital that the Federal
2343 Government create standard rules of the road for developers
2344 that will give our communities confidence in the safety of
2345 these projects.

2346 Now, as much as we have done a good job getting to
2347 bipartisan agreement, the bill isn't perfect. And I think we
2348 have to continue to work to ensure that PHMSA is forward-
2349 looking when it comes to pipeline safety, and to ensure that
2350 that meets tomorrow's challenges, not just yesterday's
2351 challenges. And it is why I worked to include the PHMSA
2352 technology pilot program in the 2020 reauthorization bill
2353 back when I was on the T&I Committee.

2354 And I think this technology demonstration program is
2355 really important. That is what I have heard from people who
2356 are doing the work out in the field to operate these
2357 pipelines, that they want to have the most cutting-edge
2358 technology to monitor for corrosion, to make sure that they
2359 are able to test pipelines. And this program is a really
2360 important piece of that, and I am really sorry that it didn't

2361 make it into this bill. I think that it is something that we
2362 need and we should be authorizing, we should be continuing.

2363 And so I am really hopeful that we can work to include
2364 it during the conference process as we move this forward, but
2365 that is one of many things that I would like to see
2366 addressed. So many of the others have been addressed in this
2367 bill, including, I think, the concerns we talked about in the
2368 markup about the importance of finding a balance for safety
2369 of operation. And we do need to make sure that these
2370 pipelines can be operated safely -- safely. That is
2371 paramount, while also recognizing the important
2372 constitutional rights of Americans to express their opinions
2373 and views.

2374 And so I am glad that we were able to do this work
2375 following the last committee markup. I hope we can do just a
2376 little bit more in the conference process, but I support the
2377 bill and look forward to voting for it shortly.

2378 Thank you so much, and I yield back.

2379 *The Chair. Thank you. The gentlelady yields back. Is
2380 there further discussion on the bill?

2381 The gentleman from California is recognized on the bill.

2382 *Mr. Mullin. Thank you, Mr. Chair. I certainly
2383 appreciate that your team has worked to improve the bill
2384 since subcommittee markup. However, I remain concerned that
2385 this version still includes provisions that would undermine

2386 PHMSA's ability to ensure safety.

2387 As you know, pipeline safety is a particularly salient
2388 issue in my district, given the deadly pipeline explosion in
2389 San Bruno nearly 15 years ago. Specifically, I am concerned
2390 that section 5 places rigid constraints on PHMSA's special
2391 permits. By preventing the agency from requiring other
2392 conditions for special permits, we are tying its hands and
2393 limiting its ability to ensure safety. PHMSA needs the
2394 flexibility to impose strong guardrails when operators seek
2395 to bypass Federal regulations.

2396 So I urge my colleagues to reconsider this provision so
2397 we can advance a reauthorization bill that prioritizes safety
2398 over regulatory shortcuts.

2399 And with that I yield back.

2400 *The Chair. The gentleman yields back. Is there
2401 further discussion on the bill?

2402 Seeing none, are there any amendments?

2403 The gentleman from Texas, you are recognized.

2404 *Mr. Weber. Mr. Chairman, yes, I have an amendment in
2405 the nature -- now that I have read the whole thing, it is
2406 ANS_HR9338_01.

2407 And look, I appreciate my colleague from --

2408 *The Chair. The gentleman has to report the amendment.

2409 *Mr. Weber. Thank you.

2410 *The Clerk. Amendment in the nature of a substitute to

2411 H.R. 9338 offered by Mr. Weber.

2412 *The Chair. Without objection, the amendment is
2413 dispensed with.

2414 [The amendment of Mr. Weber follows:]

2415

2416 *****COMMITTEE INSERT*****

2417

2418 *The Chair. And the gentleman from Texas is now
2419 recognized for five minutes.

2420 *Mr. Weber. Thank you, Mr. Chairman. I appreciate all
2421 of the comments and all the discussion that we are having,
2422 because all this stuff is important to us, and I appreciate
2423 us working together. I appreciate the ranking member being
2424 in support of it, and I am looking forward to it passing.

2425 And with that, Mr. Chairman, I yield back.

2426 *The Chair. The gentleman yields back. Is there
2427 discussion of the amendment?

2428 The gentlelady from Washington is recognized to speak on
2429 the amendment in the nature of a substitute for five minutes.

2430 *Ms. Schrier. Thank you, Mr. Chairman. I really
2431 appreciate the efforts of Chair Guthrie and Ranking Member
2432 Pallone to negotiate a robust pipeline safety bill. Congress
2433 last passed a pipeline safety programs bill in 2020, and it
2434 was supposed to be updated and reauthorized in 2023, so we
2435 are overdue.

2436 Pipeline safety is not to be taken for granted. It was
2437 the lethal 1999 Bellingham explosion along the BP Olympic
2438 pipeline that prompted major reforms to protect public health
2439 and safety. But my constituents were reminded just seven
2440 months ago from an oil spill on the same pipeline that there
2441 are still safety gaps that pipeline owners need to address.
2442 The most recent spill was actually discovered by a blueberry

2443 farmer tending his land and not by BP, the operator of the
2444 pipeline. And this spill caused severe jet fuel shortages
2445 canceling flights, resulting in the governor declaring a
2446 state of emergency. And it is not the first time this has
2447 happened. This marked the 26th reportable incident in 13
2448 years.

2449 There is more that I would have liked to see included in
2450 this bill. For example, I would have liked to see
2451 requirements for more technology that makes pipelines safer
2452 and makes any spills smaller, like advanced rupture
2453 mitigation valves. This technology could have reduced the
2454 impact of the 2023 Conway spill, when 21,000 gallons of gas
2455 from the Olympic pipeline went straight into a fish-bearing
2456 stream and temporarily closed a nearby school.

2457 This committee also could have required performance
2458 standards on leak detention -- detection technologies to make
2459 sure that current detection systems really work. The 2025
2460 spill wasn't detected until that blueberry farmer just
2461 happened to see it, and it was a big leak.

2462 So while I will be voting yes due to the urgent need to
2463 authorize and update our pipeline safety programs and I
2464 applaud the bipartisan work to get here, we do need to do
2465 even more to ensure companies like BP are safeguarding their
2466 pipelines for our public health and safety.

2467 Thank you, I yield back.

2468 *The Chair. The gentlelady yields back. Is there
2469 further discussion on the amendment?

2470 Seeing none on the amendment -- the gentleman from
2471 Louisiana is recognized for five minutes to speak on the
2472 amendment.

2473 *Mr. Carter of Louisiana. Thank you, Mr. Chairman.

2474 I am glad to see the many improvements made in this
2475 amendment of this important pipeline safety bill, including
2476 fully reauthorizing the safety program within the Pipeline
2477 and Hazardous Materials Administration on par with the levels
2478 approved by the other committees of jurisdiction.

2479 Pipeline safety is not a partisan issue, it is a public
2480 safety issue, and Congress has a responsibility to act.
2481 Reauthorizing PHMSA to -- the Federal agency that oversees
2482 pipeline safety nationwide is a regular, reoccurring duty of
2483 Congress. This is how we make sure our pipeline safety
2484 standards and regulations stay current with new technology,
2485 new risks, and the realities of aging infrastructure.

2486 And nowhere are the stakes higher than in my district in
2487 Louisiana. We are one of the most -- we are one of the
2488 nation's leading energy-producing states with a dense network
2489 of natural gas, oil, and petrochemical pipelines connecting
2490 wetlands, refineries, and export terminals along the
2491 Mississippi River and Gulf Coast. This infrastructure is the
2492 circular -- circulatory system of our state's economy, many

2493 -- moving the energy that powers homes, fuels industry, and
2494 keeps America competitive in global energy markets. Failing
2495 to get this bill right puts all of that at risk.

2496 Public safety means worker safety. The men and women
2497 who build, inspect, and maintain this infrastructure work in
2498 demanding, high-risk conditions every day. Modern pipeline
2499 safety standards, corrosion control, leak detection, pressure
2500 monitoring, and rigorous inspection protocols exist because
2501 every worker deserves to come home safely. Strong safety
2502 standards are a baseline commitment to the people who keep
2503 our energy sectors running.

2504 Pipeline safety is also critical for Louisiana's
2505 communities. When pipeline safeties fail, our communities
2506 pay the price through service disruption, evacuations,
2507 environmental damage, or even worse. When we invest in
2508 safety and modernization, those same communities can support
2509 good jobs, more reliable service, and lower long-term costs.
2510 Safety and economic -- economy -- economic competitiveness go
2511 hand in hand. A safe community is needed at all times.
2512 Energy repairs and outages (sic) reassure industry partners
2513 and investors that America's energy infrastructure is
2514 reliable.

2515 Aging infrastructure is a real risk. Like much of the
2516 rest of the nation, some of Louisiana's local gas
2517 distribution infrastructures are decades old. These legacy

2518 pipelines are more prone to leaks, which pose explosion risk,
2519 waste product, and release methane and potential greenhouse
2520 gases into communities that can least afford to have it.
2521 That is why I am happy to see the amendments reauthorize the
2522 natural gas distribution infrastructure safety and
2523 modernization program.

2524 This grant program was created under the Bipartisan
2525 Infrastructure Law, and is designed to provide millions of
2526 dollars in grant funding to small, municipal-owned utilities
2527 to replace high-risk natural gas distribution pipes. In my
2528 district the City of Donaldsonville received a \$20 million
2529 grant to replace 27.3 miles of deteriorating distribution
2530 lines, some of which had been in the ground for decades.
2531 This project eliminated leaks, improved safety, reduced
2532 environmental impact, and lowered energy bills for residents
2533 and businesses alike. This program funded a comprehensive
2534 modernization of small city gas systems that could never have
2535 been afforded on its own. And the countless other
2536 communities in America that benefit from this program in the
2537 future (sic).

2538 This is the right thing to do. Mr. Chairman, I yield
2539 back.

2540 *The Chair. The gentleman yields back. Is there
2541 further discussion on the amendment?

2542 I will recognize myself for five minutes to speak on the

2543 amendment. I won't use all five minutes, I promise.

2544 So I just want to say this bill before us is a product
2545 of extensive bipartisan negotiations and helps bring PHMSA's
2546 safety regulations into the 21st century. I appreciate all
2547 the work of the members and the staffs for doing this.

2548 The committee's narrow and streamlined PHMSA
2549 reauthorization ensures the agency's safety regulations keep
2550 pace with the technological and operational advancements that
2551 have strengthened the safety and security of our nation's
2552 pipeline infrastructure without overreaching. The bill makes
2553 common-sense updates to remove duplicative regulations that
2554 do not meaningfully improve safety. It streamlines certain
2555 permits to reflect relevant safety standards and reinforce
2556 fair process for operators and refocus PHMSA on its mission:
2557 safety.

2558 I would also like to thank my colleagues across the
2559 aisle, particularly Ranking Member Pallone and the committee
2560 staff, for meaningful and robust engagement -- as I talked
2561 during your time -- to make sure we addressed concerns that
2562 were brought up during subcommittee.

2563 So I look forward to getting this bill out of committee
2564 today, and I know we still have work to do with our
2565 colleagues at T&I and the Senate Commerce Committee on a
2566 final package.

2567 And I will yield back. And if there is no further

2568 discussion, we will adopt the amendment.

2569 So the question before the committee is adopting the
2570 amendment. If there is no further discussion, the vote
2571 occurs on the amendment.

2572 All those in favor shall signify by saying aye.

2573 All those opposed, nay.

2574 The ayes have it. Are there further amendments?

2575 Seeing none, the question occurs on adopting H.R. 9338,
2576 as amended. A roll call has been requested, and the clerk
2577 will call the roll.

2578 *The Clerk. Mr. Latta?

2579 [No response.]

2580 *The Clerk. Mr. Griffith?

2581 [No response.]

2582 *The Clerk. Mr. Bilirakis?

2583 [No response.]

2584 *The Clerk. Mr. Hudson?

2585 *Mr. Hudson. Aye.

2586 *The Clerk. Mr. Hudson votes aye.

2587 Mr. Carter of Georgia?

2588 *Mr. Carter of Georgia. Aye.

2589 *The Clerk. Mr. Carter of Georgia votes aye.

2590 Mr. Palmer?

2591 *Mr. Palmer. Aye.

2592 *The Clerk. Mr. Palmer votes aye.

2593 Mr. Dunn?
2594 [No response.]
2595 *The Clerk. Mr. Crenshaw?
2596 [No response.]
2597 *The Clerk. Mr. Joyce?
2598 [No response.]
2599 *The Clerk. Mr. Weber?
2600 *Mr. Weber. Aye.
2601 *The Clerk. Mr. Weber votes aye.
2602 Mr. Allen?
2603 *Mr. Allen. Aye.
2604 *The Clerk. Mr. Allen votes aye.
2605 Mr. Balderson?
2606 *Mr. Balderson. Aye.
2607 *The Clerk. Mr. Balderson votes aye.
2608 Mr. Fulcher?
2609 *Mr. Fulcher. Fulcher is aye.
2610 *The Clerk. Mr. Fulcher votes aye.
2611 Mr. Pfluger?
2612 *Mr. Pfluger. Aye.
2613 *The Clerk. Mr. Pfluger votes aye.
2614 Mrs. Harshbarger?
2615 *Mrs. Harshbarger. Aye.
2616 *The Clerk. Mrs. Harshbarger votes aye.
2617 Mrs. Miller-Meeks?

2618 *Mrs. Miller-Meeks. Aye.
2619 *The Clerk. Mrs. Miller-Meeks votes aye.
2620 Mrs. Cammack?
2621 [No response.]
2622 *The Clerk. Mr. Obernolte?
2623 *Mr. Obernolte. Aye.
2624 *The Clerk. Mr. Obernolte votes aye.
2625 Mr. James?
2626 *Mr. James. Aye.
2627 *The Clerk. Mr. James votes aye.
2628 Mr. Bentz?
2629 *Mr. Bentz. Aye.
2630 *The Clerk. Mr. Bentz votes aye.
2631 Mrs. Houchin?
2632 *Mrs. Houchin. Aye.
2633 *The Clerk. Mrs. Houchin votes aye.
2634 Mr. Fry?
2635 [No response.]
2636 *The Clerk. Ms. Lee?
2637 *Ms. Lee. Aye.
2638 *The Clerk. Ms. Lee votes aye.
2639 Mr. Langworthy?
2640 *Mr. Langworthy. Aye.
2641 *The Clerk. Mr. Langworthy votes aye.
2642 Mr. Kean?

2643 *Mr. Kean. Aye.
2644 *The Clerk. Mr. Kean votes aye.
2645 Mr. Rulli?
2646 *Mr. Rulli. Aye.
2647 *The Clerk. Mr. Rulli votes aye.
2648 Mr. Evans?
2649 *Mr. Evans. Aye.
2650 *The Clerk. Mr. Evans votes aye.
2651 Mr. Goldman?
2652 *Mr. Goldman. Aye.
2653 *The Clerk. Mr. Goldman votes aye.
2654 Mrs. Fedorchak?
2655 [No response.]
2656 *The Clerk. Mr. Pallone?
2657 *Mr. Pallone. Aye.
2658 *The Clerk. Mr. Pallone votes aye.
2659 Ms. DeGette?
2660 [No response.]
2661 *Ms. Schakowsky. No, I am sorry.
2662 *The Clerk. Ms. Schakowsky?
2663 Ms. Schakowsky votes no.
2664 Ms. Matsui?
2665 *Ms. Matsui. No.
2666 *The Clerk. Ms. Matsui votes no.
2667 Ms. Castor?

2668 *Ms. Castor. Yes.

2669 *The Clerk. Ms. Castor votes aye.

2670 Mr. Tonko?

2671 *Mr. Tonko. No.

2672 *The Clerk. Mr. Tonko votes no.

2673 Ms. Clarke?

2674 *Ms. Clarke. No.

2675 *The Clerk. Ms. Clarke votes no.

2676 Mr. Ruiz?

2677 *Mr. Ruiz. No.

2678 *The Clerk. Mr. Ruiz votes no.

2679 Mr. Peters?

2680 [No response.]

2681 *The Clerk. Mrs. Dingell?

2682 *Mrs. Dingell. Aye.

2683 *The Clerk. Mrs. Dingell votes aye.

2684 Mr. Veasey?

2685 *Mr. Veasey. Aye.

2686 *The Clerk. Mr. Veasey votes aye.

2687 Ms. Kelly?

2688 *Ms. Kelly. No.

2689 *The Clerk. Ms. Kelly votes no.

2690 Ms. Barragan?

2691 *Ms. Barragan. No.

2692 *The Clerk. Ms. Barragan votes no.

2693 Mr. Soto?

2694 *Mr. Soto. Aye.

2695 *The Clerk. Mr. Soto votes aye.

2696 Ms. Schrier?

2697 *Ms. Schrier. Aye.

2698 *The Clerk. Ms. Schrier votes aye.

2699 Mrs. Trahan?

2700 *Mrs. Trahan. Aye.

2701 *The Clerk. Mrs. Trahan votes aye.

2702 Mrs. Fletcher?

2703 *Mrs. Fletcher. Aye.

2704 *The Clerk. Mrs. Fletcher votes aye.

2705 Ms. Ocasio-Cortez?

2706 *Ms. Ocasio-Cortez. No.

2707 *The Clerk. Ms. Ocasio-Cortez votes no.

2708 Mr. Auchincloss?

2709 *Mr. Auchincloss. Aye.

2710 *The Clerk. Mr. Auchincloss votes aye.

2711 Mr. Carter of Louisiana?

2712 *Mr. Carter of Louisiana. Aye.

2713 *The Clerk. Mr. Carter of Louisiana votes aye.

2714 Mr. Menendez?

2715 *Mr. Menendez. Aye.

2716 *The Clerk. Mr. Menendez votes aye.

2717 Mr. Mullin?

2718 *Mr. Mullin. No.
2719 *The Clerk. Mr. Mullin votes no.
2720 Mr. Landsman?
2721 *Mr. Landsman. Aye.
2722 *The Clerk. Mr. Landsman votes aye.
2723 Ms. McClellan?
2724 *Ms. McClellan. Aye.
2725 *The Clerk. Ms. McClellan votes aye.
2726 Chairman Guthrie?
2727 *The Chair. Aye. Any --
2728 *The Clerk. Chairman Guthrie votes aye.
2729 *The Chair. All right. So Mr. Latta?
2730 *Mr. Latta. Aye.
2731 *The Clerk. Mr. Latta votes aye.
2732 *The Chair. Mr. Griffith?
2733 *Mr. Griffith. Aye.
2734 *The Clerk. Mr. Griffith votes aye.
2735 *The Chair. Mr. Bilirakis?
2736 *Mr. Bilirakis. Aye.
2737 *The Clerk. Mr. Bilirakis votes aye.
2738 *The Chair. Dr. Joyce?
2739 *Mr. Joyce. Aye.
2740 *The Clerk. Mr. Joyce votes aye.
2741 *The Chair. Mr. Peters?
2742 *The Clerk. Mr. Peters?

2743 *Mr. Peters. Votes aye.

2744 *The Clerk. Votes aye.

2745 *The Chair. Mr. -- Dr. Ruiz.

2746 *Mr. Ruiz. Ruiz off no and on yes.

2747 *The Clerk. Mr. Ruiz is off no and on aye.

2748 *The Chair. Are there any further -- seeing no one
2749 presenting to call the -- answer the roll, the clerk will
2750 report.

2751 [Pause.]

2752 *The Clerk. Mr. Chairman, on that --

2753 *The Chair. Before you report, the gentlelady from
2754 Florida, how is she recorded?

2755 *Mrs. Cammack. Yea.

2756 *The Chair. Yea, okay.

2757 *The Clerk. Mrs. Cammack votes aye.

2758 *The Chair. Okay. The clerk will report.

2759 *The Clerk. Mr. Chairman, on that vote there were 41
2760 ayes and 8 noes.

2761 *The Chair. The ayes have it, and the bill is adopted.
2762 The chair calls up H.R. 9332 and asks the clerk to
2763 report.

2764 *The Clerk. H.R. 9332, a bill to require the Federal --

2765 *The Chair. Without objection, the first reading of the
2766 bill is dispensed with, and the bill will be up for amendment
2767 at any point.

2768 So ordered.

2769 [The bill follows:]

2770

2771 *****COMMITTEE INSERT*****

2772

2773 *The Chair. Does anyone seek to be recognized on the
2774 bill?

2775 *Mr. Tonko. Mr. Chair? Oh, on the bill.

2776 *The Chair. For what purpose does the gentleman from
2777 Ohio seek recognition?

2778 *Mr. Balderson. Mr. Chairman, I move to strike the last
2779 word and speak in support of the bill.

2780 *The Chair. You are recognized for five minutes to
2781 speak on the bill.

2782 *Mr. Balderson. Thank you, Mr. Chairman. Thank you for
2783 holding this markup and including my bill, H.R. 9332, the
2784 Load Forecasting Enhancement Act.

2785 I would also like to thank my colleague from New Jersey,
2786 Congressman Menendez, for working with me on this legislation
2787 and co-leading the bill.

2788 Our electric grid has entered a period of unprecedented
2789 change. Advanced manufacturing, increased electrification,
2790 and the surge of AI data centers have created an historic
2791 increase in electricity demand. We have seen this firsthand
2792 in Ohio's 12th congressional district which has 41 data
2793 centers in operation or being built, the most in the state.
2794 My constituents are seeing these data centers being built in
2795 their neighborhoods and have serious concerns about what this
2796 rapid growth means for their families and their communities.

2797 Congress must do more to help get new generation built

2798 quickly to power this growth and ensure those large-load
2799 customers, not our constituents, are the ones paying for
2800 these upgrades and new costs. At the bare minimum, we should
2801 ensure that grid operators, state utilities, and power
2802 providers are accurately planning for this growth to keep the
2803 grid reliable and protect our constituents.

2804 This bill is about giving states and utilities the tools
2805 necessary to measure load growth so that they can
2806 appropriately plan for new generation and generation
2807 transmission. Accurate load forecasting prevents the under-
2808 building of electrical infrastructure and generation that is
2809 critical to maintaining grid reliability. And just as
2810 importantly, this bill will help prevent the over-building of
2811 unnecessary electric infrastructure for speculative projects
2812 that can end up costing ratepayers.

2813 The Load Forecasting Enhancement Act establishes
2814 regional joint boards to bring state utility regulators and
2815 FERC commissioners together to examine, identify, and report
2816 to Congress the best practices that improve the accuracy,
2817 transparency, and the accountability of projects of new
2818 electrical grid. The bill amends the Public Utility
2819 Regulatory Policies Act to require each state to consider
2820 incorporating the recommendations that lead to better load
2821 forecasting.

2822 Just last month one of the Department of Energy's

2823 national labs released a report showing data centers could
2824 double their share of U.S. power and account for 10 to 15
2825 percent of our electricity use by 2030. Given this
2826 uncertainty with projected demand, utilities and states need
2827 better tools to distinguish between speculative demand
2828 projects and projects that have demonstrated a genuine
2829 commitment to moving forward. Better forecasting means
2830 better planning, and better planning means a more reliable
2831 grid and more responsible investment decisions.

2832 I urge my colleagues on the committee to support this
2833 bill and I yield back, Mr. Chairman.

2834 *The Chair. The gentleman yields back. Is there anyone
2835 seeking recognition to speak on the bill?

2836 The gentleman from New Jersey is recognized for five
2837 minutes to speak on the bill.

2838 *Mr. Menendez. Thank you, Chairman. I am glad the
2839 committee is advancing a slate of bills that begin to address
2840 challenges to our grid brought on by the growth of AI data
2841 centers, and I am proud to work with Congressman Balderson on
2842 H.R. 9332, the Load Forecasting Enhancement Act.

2843 This bill would enhance our ability to forecast future
2844 demands on our energy grid and improve a vital piece of long-
2845 term planning in our energy systems. Accurate load
2846 forecasting is essential to making sure we have enough power
2847 supply to meet the demands of tomorrow. This bill would push

2848 state utility commissions and investor-owned utilities to
2849 adopt best practices when forecasting demand including large
2850 loads such as AI data centers and, in turn, make sure that we
2851 have an accurate idea of how much energy we will need years
2852 down the line.

2853 Improving load forecasting will help prevent blackouts
2854 and brownouts to make sure our constituents don't experience
2855 drastic spikes in their energy bills. It will help us make
2856 sure we have the energy infrastructure we need to support new
2857 innovations and technology, manufacturing, and keep our homes
2858 cool in the summer and warm in the winter.

2859 This bill and others before the committee today are an
2860 important first step in the right direction, but they are a
2861 first step and we need to use every tool in the toolbox to
2862 address these issues facing our grid and protect our
2863 constituents from rising energy costs and blackouts and
2864 brownouts. That means making sure tech companies that are
2865 developing AI data centers are held accountable for the
2866 impact they have in our communities, and that means fighting
2867 for more transparency on data centers' energy usage, as well
2868 as their environmental and health impacts.

2869 Today's markup is a step in the right direction. I am
2870 proud to work on bipartisan legislation to address these
2871 pressing needs. I encourage my colleagues to continue this
2872 work and vote in support of this bill.

2873 I yield back.

2874 *The Chair. The gentleman yields back. Is there
2875 further discussion on the bill?

2876 The gentleman from Georgia is recognized for five
2877 minutes to speak on the bill.

2878 *Mr. Carter of Georgia. Thank you, Mr. Chairman, and
2879 Mr. Chairman, I rise today in support of the Load Forecasting
2880 Enhancement Act.

2881 This legislation offers a real solution to the
2882 unprecedented load growth this country is experiencing.
2883 Under this legislation FERC would convene regional joint
2884 boards with public utility commissions to study and identify
2885 best practices for electric load forecasting. FERC would
2886 then be able to report its findings and recommend how we in
2887 Congress can best improve load forecasting.

2888 Preparing for load growth, which we know is coming, is
2889 an absolute necessity. In our diverse country we have so
2890 many different states with different energy types and energy
2891 needs. Encouraging collaboration, idea sharing, and
2892 recommendations for Congress will ensure state and Federal
2893 leaders alike are prepared to accurately forecast load growth
2894 and prepare for it.

2895 Thank you to Representatives Balderson and Menendez for
2896 introducing this critical bipartisan legislation.

2897 And I yield back.

2898 *The Chair. The gentleman yields back. Is there
2899 further discussion on the bill?

2900 The gentlelady from Virginia is recognized for five
2901 minutes to speak on the bill.

2902 *Ms. McClellan. Thank you, Mr. Chair. Thank you, Mr.
2903 Chair.

2904 With projections showing that data center energy
2905 consumption could double or triple in the next 2 years,
2906 accounting for up to 12 percent of U.S. electricity use, we
2907 have to work smarter to account for and prepare for the
2908 impact that data centers are having on the grid. The Load
2909 Forecasting Enhancement Act is an important first step to do
2910 just that by requiring FERC to establish regional boards to
2911 study best practices for forecasting power and demand.

2912 In Virginia and across the country, the siting,
2913 planning, and construction of data centers are handled almost
2914 entirely at the local level, with the state playing a role
2915 mostly when it is time to bring the data center online. And
2916 our Virginia localities have tended to prioritize the revenue
2917 impact to their budget over the impact to the grid. Now,
2918 that is understandable when, as one county manager in a rural
2919 part of my district said that the real estate revenue alone
2920 from one data center to looking to locate there could fund
2921 the building of a brand-new school they desperately needed.
2922 And local economic development, planning, and zoning

2923 officials often don't have the expertise to factor in the
2924 impact these data centers will have on the grid.

2925 This fragmented system of planning and approvals makes
2926 it difficult to fully prepare for the impact of the ongoing
2927 rapid build-out of data centers on our grid and its
2928 reliability. This is not sustainable. The Load Forecasting
2929 Enhancement Act seeks to create a more cohesive approach,
2930 where FERC works with states to improve oversight,
2931 accountability, and transparency in load forecasting, and
2932 bring more stakeholders into that process so that we have a
2933 better idea of how to prepare for and mitigate the impact
2934 that data centers will have on the grid and on energy
2935 affordability for American families and small businesses that
2936 are especially feeling the impact. We need to make sure that
2937 local governments are part of that stakeholder process.

2938 I urge my colleagues to support this legislation and to
2939 continue to work with us on proposals that will increase all
2940 stakeholder engagement and improve coordination at all levels
2941 of government to address the impacts of data center.

2942 Now, I also -- given the discussion earlier today over
2943 public opinion turning against data centers, I do want to
2944 take a moment to connect some dots that explain the hostility
2945 we are seeing in rural localities that show that, while we
2946 legislate in silos, people don't live in silos. In a recent
2947 discussion that I had with some residents in rural

2948 communities, one person made a critically important point:
2949 Why are rural communities bearing the brunt of the economic
2950 and environmental impacts of data centers when they are still
2951 not connected to the internet through broadband? That is a
2952 critically important perspective that we should keep in mind
2953 as we address not only the energy impact of data centers, but
2954 we act to ensure that the benefits of the digital ecosystem
2955 that they support leave no community behind.

2956 And with that I yield back.

2957 *The Chair. The gentlelady yields back. Is there
2958 further discussion on the bill?

2959 Seeing none, are there any amendments to the bill?

2960 *Mr. Tonko. Mr. Chair?

2961 *The Chair. The gentleman from New York is recognized
2962 -- for what purpose does the gentleman from New York seek
2963 recognition?

2964 *Mr. Tonko. Mr. Chair, I have an amendment at the desk.

2965 *The Chair. The clerk will report the amendment.

2966 *The Clerk. TONKO_044, amendment to H.R. --

2967 *The Chair. Without objection, the reading of the
2968 amendment is dispensed with.

2969 [The amendment of Mr. Tonko follows:]

2970

2971 *****COMMITTEE INSERT*****

2972

2973 *The Chair. And the gentleman is recognized for five
2974 minutes in support of the amendment.

2975 *Mr. Tonko. Thank you, Mr. Chair. I begin by thanking
2976 Representatives Balderson and Menendez for their outstanding
2977 work on this bill.

2978 I want to be clear that I support the underlying bill,
2979 but I do believe that it could be improved upon by explicitly
2980 authorizing the Department of Energy's role in providing
2981 technical assistance to support our nation's load forecasting
2982 needs.

2983 I think we can all agree that there are real challenges
2984 associated with large and uncertain load growth due to the
2985 demand of data centers. And if we fail to accurately plan
2986 for load growth, there will be serious risks to the
2987 reliability and affordability of our electricity system.
2988 Working to harmonize load forecasting methods through
2989 regional boards and leveraging the expertise of our state
2990 commissions, as is done in this bill, is a great step. But
2991 if this is such a big problem, shouldn't we want our nation's
2992 leading minds working on the electricity system to help
2993 address it?

2994 We heard from Secretary Wright at the budget hearing
2995 that the Department of Energy is focused on load forecasting,
2996 and we know there is amazing expertise in the national labs.
2997 So if we are going to make progress in planning for our

2998 future electric demand, we should be utilizing all the tools
2999 in our toolbox, including those that exist at DoE.

3000 This amendment would simply direct DoE to establish a
3001 technical assistance program to provide modeling, analysis,
3002 best practices, and other forms of support to states, grid
3003 operators, utilities, and independent power producers
3004 responsible for electric load growth planning. It would also
3005 explicitly authorize DoE to coordinate with and provide
3006 technical assistance to the regional boards that are
3007 established by the underlying bill. This will allow these
3008 boards to have access to all the data modeling and technical
3009 support possible to help ensure their success.

3010 During the subcommittee markup I emphasized the
3011 importance of technical assistance of this kind that -- and
3012 that it can have a great amount of effort made to support
3013 municipal utilities and rural co-ops that may not have the
3014 capacity to model load growth like their larger utility
3015 peers. But DoE technical assistance should not just be
3016 limited to smaller entities, especially since the goals of
3017 this bill are to broaden coordination amongst all entities
3018 with a responsibility in planning for load growth.

3019 The amendment is simple: it authorizes something that
3020 everyone agrees DoE can and should be doing to help address
3021 an emerging challenge facing our electricity system. It
3022 would provide clear direction that Congress wants the

3023 Department to leverage its expertise to engage further on
3024 this issue, and it would do so by providing support to the
3025 boards that would be created by this bill.

3026 I urge members to support this amendment and authorize
3027 DoE to provide technical assistance to all entities that have
3028 a responsibility in planning for electric load growth, simply
3029 making an outstanding bill even better.

3030 With that, Mr. Chair, I thank you and I yield back.

3031 *The Chair. The gentleman yields back. Is there
3032 further discussion on the amendment?

3033 The gentleman from Ohio is recognized to speak on the
3034 amendment.

3035 *Mr. Balderson. Mr. Chair, I move to strike the last
3036 word and speak --

3037 *The Chair. The gentleman is recognized to speak on the
3038 amendment.

3039 *Mr. Balderson. Thank you, Mr. Chairman, and this is
3040 tough. I am opposing my dear friend's amendment. And Mr.
3041 Tonko and I have done a lot of legislation together, but as
3042 currently drafted this amendment would create an open-ended
3043 new program at the Department of Energy on load forecasting.

3044 The underlying bill is an important measure to improve
3045 the accuracy of electricity demand projections. As we have
3046 discussed over the last several months, more accurate
3047 forecasting will lead to more cost-effective investments to

3048 meet a growing electric demand.

3049 The Load Forecasting Enhancement Act, using regional
3050 joint boards and PURPA, encourages a collective --
3051 collaborative, excuse me -- collaborative relationship
3052 between states and the Federal Government to improve our
3053 collective understanding of electrical growth -- demand
3054 growth. Importantly, this bill also provides technical
3055 assistance to state energy offices to work in hand with state
3056 PUCs and utilities for economic development purposes.

3057 However, the amendment being offered by my colleague is
3058 expansive, unnecessary, and needs additional work to ensure
3059 valuable taxpayer resources are protected from abuse. This
3060 amendment would provide sweeping technical assistance
3061 authority to utilities of all types, regardless of size, and
3062 a host of entities involved in the generation, transmission,
3063 and distribution of electricity. This would encompass
3064 thousands of utilities, power generators, transmission
3065 owners, and others.

3066 And while the underlying bill offers a smart and
3067 balanced approach to ensure states are working in harmony
3068 with FERC, this amendment fails to do so. I appreciate the
3069 amendment would direct DoE assistance to the joint boards.
3070 However, the amendment doesn't clarify that DoE's
3071 recommendations or best practices provided to utilities and
3072 more power providers be based on the findings of the joint

3073 boards, the final report in the bill, or state policies
3074 enacted based on these findings. Unfortunately, this could
3075 lead to DoE providing conflicting standards or best
3076 practices, leading to confusion between utilities, power
3077 providers, and states. Additionally, the amendment provides
3078 no clarity on taxpayer dollars being used to fulfill this
3079 expansive new program.

3080 Throughout this process I have worked in good faith with
3081 my Democratic colleagues, including my co-lead, Mr. Menendez,
3082 to advance this policy through full committee. Since our
3083 legislative hearing in April, our side of the aisle has
3084 continued offering to work alongside Mr. Tonko to find a
3085 compromise on ideas for more targeted approach and to address
3086 our concerns of unfunded mandates. Unfortunately, those
3087 offers have been rejected, and I am concerned that this new
3088 policy undermines the bipartisan work of our underlying
3089 legislation. For those reasons, I urge my colleagues to
3090 oppose the amendment.

3091 And I yield back, Mr. Chairman.

3092 *Mr. Latta. [Presiding.] Thank you. The gentleman
3093 yields back. Is there a further discussion on the amendment?

3094 Hearing none, if there is no further discussion on the
3095 amendment, all those in favor shall signify by saying aye.

3096 Those opposed, nay.

3097 The nays have it.

3098 *Mr. Tonko. Mr. Chair, I ask for a recorded vote,
3099 please.

3100 *Mr. Latta. And the gentleman asks for a roll call
3101 vote. The -- on -- the clerk will call the roll on the ANS.

3102 *The Clerk. Mr. Latta?

3103 *Mr. Latta. No.

3104 *The Clerk. Mr. Latta votes no.

3105 Mr. Griffith?

3106 [No response.]

3107 *The Clerk. Mr. Bilirakis?

3108 *Mr. Bilirakis. No.

3109 *The Clerk. Mr. Bilirakis votes no.

3110 Mr. Hudson?

3111 *Mr. Hudson. No.

3112 *The Clerk. Mr. Hudson votes no.

3113 Mr. Carter of Georgia?

3114 *Mr. Carter of Georgia. No.

3115 *The Clerk. Mr. Carter of Georgia votes no.

3116 Mr. Palmer?

3117 *Mr. Palmer. No.

3118 *The Clerk. Mr. Palmer votes no.

3119 Mr. Dunn?

3120 [No response.]

3121 *The Clerk. Mr. Crenshaw?

3122 [No response.]

3123 *The Clerk. Mr. Joyce?
3124 [No response.]
3125 *The Clerk. Mr. Weber?
3126 *Mr. Weber. No.
3127 *The Clerk. Mr. Weber votes no.
3128 Mr. Allen?
3129 *Mr. Allen. No.
3130 *The Clerk. Mr. Allen votes no.
3131 Mr. Balderson?
3132 *Mr. Balderson. No.
3133 *The Clerk. Mr. Balderson votes no.
3134 Mr. Fulcher?
3135 *Mr. Fulcher. Fulcher is no.
3136 *The Clerk. Mr. Fulcher votes no.
3137 Mr. Pfluger?
3138 *Mr. Pfluger. No.
3139 *The Clerk. Mr. Pfluger votes no.
3140 Mrs. Harshbarger?
3141 *Mrs. Harshbarger. No.
3142 *The Clerk. Mrs. Harshbarger votes no.
3143 Mrs. Miller-Meeks?
3144 [No response.]
3145 *The Clerk. Mrs. Cammack?
3146 *Mrs. Cammack. No.
3147 *The Clerk. Mrs. Cammack votes no.

3148 Mr. Oubernolte?
3149 *Mr. Oubernolte. No.
3150 *The Clerk. Mr. Oubernolte votes no.
3151 Mr. James?
3152 *Mr. James. No.
3153 *The Clerk. Mr. James votes no.
3154 Mr. Bentz?
3155 *Mr. Bentz. No.
3156 *The Clerk. Mr. Bentz votes no.
3157 Mrs. Houchin?
3158 *Mrs. Houchin. No.
3159 *The Clerk. Mrs. Houchin votes no.
3160 Mr. Fry?
3161 [No response.]
3162 *The Clerk. Ms. Lee?
3163 *Ms. Lee. No.
3164 *The Clerk. Ms. Lee votes no.
3165 Mr. Langworthy?
3166 *Mr. Langworthy. No.
3167 *The Clerk. Mr. Langworthy votes no.
3168 Mr. Kean?
3169 *Mr. Kean. No.
3170 *The Clerk. Mr. Kean votes no.
3171 Mr. Rulli?
3172 *Mr. Rulli. No.

3173 *The Clerk. Mr. Rulli votes no.
3174 Mr. Evans?
3175 *Mr. Evans. No.
3176 *The Clerk. Mr. Evans votes no.
3177 Mr. Goldman?
3178 *Mr. Goldman. No.
3179 *The Clerk. Mr. Goldman votes no.
3180 Mrs. Fedorchak?
3181 [No response.]
3182 *The Clerk. Mr. Pallone?
3183 *Mr. Pallone. Aye.
3184 *The Clerk. Mr. Pallone votes aye.
3185 Ms. DeGette?
3186 [No response.]
3187 *The Clerk. Ms. Schakowsky?
3188 *Ms. Schakowsky. Aye.
3189 *The Clerk. Ms. Schakowsky votes aye.
3190 Ms. Matsui?
3191 *Ms. Matsui. Aye.
3192 *The Clerk. Ms. Matsui votes aye.
3193 Ms. Castor?
3194 *Ms. Castor. Aye.
3195 *The Clerk. Ms. Castor votes aye.
3196 Mr. Tonko?
3197 *Mr. Tonko. Aye.

3198 *The Clerk. Mr. Tonko votes aye.
3199 Ms. Clarke?
3200 *Ms. Clarke. Aye.
3201 *The Clerk. Ms. Clarke votes aye.
3202 Mr. Ruiz?
3203 *Mr. Ruiz. Aye.
3204 *The Clerk. Mr. Ruiz votes aye.
3205 Mr. Peters?
3206 *Mr. Peters. Aye.
3207 *The Clerk. Mr. Peters votes aye.
3208 Mrs. Dingell?
3209 [No response.]
3210 *The Clerk. Mr. Veasey?
3211 *Mr. Veasey. Aye.
3212 *The Clerk. Mr. Veasey votes aye.
3213 Ms. Kelly?
3214 *Ms. Kelly. Aye.
3215 *The Clerk. Ms. Kelly votes aye.
3216 Ms. Barragan?
3217 *Ms. Barragan. Aye.
3218 *The Clerk. Ms. Barragan votes aye.
3219 Mr. Soto?
3220 *Mr. Soto. Aye.
3221 *The Clerk. Mr. Soto votes aye.
3222 Ms. Schrier?

3223 *Ms. Schrier. Aye.
3224 *The Clerk. Ms. Schrier votes aye.
3225 Mrs. Trahan?
3226 *Mrs. Trahan. Aye.
3227 *The Clerk. Mrs. Trahan votes aye.
3228 Mrs. Fletcher?
3229 [No response.]
3230 *The Clerk. Ms. Ocasio-Cortez?
3231 *Ms. Ocasio-Cortez. Aye.
3232 *The Clerk. Ms. Ocasio-Cortez votes aye.
3233 Mr. Auchincloss?
3234 *Mr. Auchincloss. Aye.
3235 *The Clerk. Mr. Auchincloss votes aye.
3236 Mr. Carter of Louisiana?
3237 *Mr. Carter of Louisiana. Aye.
3238 *The Clerk. Mr. Carter of Louisiana votes aye.
3239 Mr. Menendez?
3240 *Mr. Menendez. Aye.
3241 *The Clerk. Mr. Menendez votes aye.
3242 Mr. Mullin?
3243 *Mr. Mullin. Aye.
3244 *The Clerk. Mr. Mullin votes aye.
3245 Mr. Landsman?
3246 *Mr. Landsman. Aye.
3247 *The Clerk. Mr. Landsman votes aye.

3248 Ms. McClellan?

3249 *Ms. McClellan. Aye.

3250 *The Clerk. Ms. McClellan votes aye.

3251 Chairman Guthrie?

3252 *The Chair. Aye.

3253 *The Clerk. Chairman Guthrie votes --

3254 *The Chair. Oh, I'm sorry, no.

3255 [Laughter.]

3256 *The Clerk. Mr. Chairman is off aye and on no.

3257 *Mr. Latta. Are there members wishing to record their

3258 vote?

3259 How is the gentleman from Virginia recorded?

3260 *Mr. Griffith. Griffith is no.

3261 *The Clerk. Mr. Griffith votes no.

3262 *Mr. Latta. The gentleman from Texas?

3263 *Mr. Crenshaw. Crenshaw, no.

3264 *The Clerk. Mr. Crenshaw --

3265 *Mr. Latta. The gentleman from Pennsylvania?

3266 *The Clerk. -- votes no.

3267 *Mr. Joyce. No.

3268 *The Clerk. Mr. Joyce votes no.

3269 *Mr. Latta. Are there any other members?

3270 The clerk will report the result.

3271 [Pause.]

3272 *The Clerk. Chairman, on that vote there were 21 ayes

3273 and 26 noes.

3274 *Mr. Latta. Thank you very much. The amendment is not
3275 agreed to.

3276 Are there further amendments?

3277 Hearing none, the question now occurs on adopting H.R.
3278 9332. A roll call vote has been requested and the clerk will
3279 call the roll.

3280 *The Clerk. Mr. Latta?

3281 *Mr. Latta. Aye.

3282 *The Clerk. Mr. Latta votes aye.

3283 Mr. Griffith?

3284 [No response.]

3285 *The Clerk. Mr. Bilirakis?

3286 *Mr. Bilirakis. Aye.

3287 *The Clerk. Mr. Bilirakis votes aye.

3288 Mr. Hudson?

3289 *Mr. Hudson. Aye.

3290 *The Clerk. Mr. Hudson votes aye.

3291 Mr. Carter of Georgia?

3292 *Mr. Carter of Georgia. Aye.

3293 *The Clerk. Mr. Carter of Georgia votes aye.

3294 Mr. Palmer?

3295 *Mr. Palmer. Aye.

3296 *The Clerk. Mr. Palmer votes aye.

3297 Mr. Dunn?

3298 [No response.]
3299 *The Clerk. Mr. Crenshaw?
3300 [No response.]
3301 *The Clerk. Mr. Joyce?
3302 [No response.]
3303 *The Clerk. Mr. Weber?
3304 [No response.]
3305 *The Clerk. Mr. Allen?
3306 *Mr. Allen. Aye.
3307 *The Clerk. Mr. Allen votes aye.
3308 Mr. Balderson?
3309 *Mr. Balderson. Aye.
3310 *The Clerk. Mr. Balderson votes aye.
3311 Mr. Fulcher?
3312 [No response.]
3313 *The Clerk. Mr. Pfluger?
3314 *Mr. Pfluger. Aye.
3315 *The Clerk. Mr. Pfluger votes aye.
3316 Mrs. Harshbarger?
3317 *Mrs. Harshbarger. Aye.
3318 *The Clerk. Mrs. Harshbarger votes aye.
3319 Mrs. Miller-Meeks?
3320 [No response.]
3321 *The Clerk. Mrs. Cammack?
3322 [No response.]

3323 *The Clerk. Mr. Obernolte?
3324 *Mr. Obernolte. Aye.
3325 *The Clerk. Mr. Obernolte votes aye.
3326 Mr. James?
3327 [No response.]
3328 *The Clerk. Mr. Bentz?
3329 [No response.]
3330 *The Clerk. Mrs. Houchin?
3331 *Mrs. Houchin. No -- aye.
3332 *The Clerk. Mrs. Houchin votes aye.
3333 Mr. Fry?
3334 [No response.]
3335 *The Clerk. Ms. Lee?
3336 *Ms. Lee. Aye.
3337 *The Clerk. Ms. Lee votes aye.
3338 Mr. Langworthy?
3339 *Mr. Langworthy. Aye.
3340 *The Clerk. Mr. Langworthy votes aye.
3341 Mr. Kean?
3342 *Mr. Kean. Aye.
3343 *The Clerk. Mr. Kean votes aye.
3344 Mr. Rulli?
3345 *Mr. Rulli. Aye.
3346 *The Clerk. Mr. Rulli votes aye.
3347 Mr. Evans?

3348 *Mr. Evans. Aye.
3349 *The Clerk. Mr. Evans votes aye.
3350 Mr. Goldman?
3351 *Mr. Goldman. Aye.
3352 *The Clerk. Mr. Goldman votes aye.
3353 Mrs. Fedorchak?
3354 [No response.]
3355 *The Clerk. Mr. Pallone?
3356 *Mr. Pallone. Aye.
3357 *The Clerk. Mr. Pallone votes aye.
3358 Ms. DeGette?
3359 [No response.]
3360 *The Clerk. Ms. Schakowsky?
3361 *Ms. Schakowsky. Aye.
3362 *The Clerk. Ms. Schakowsky votes aye.
3363 Ms. Matsui?
3364 *Ms. Matsui. Aye.
3365 *The Clerk. Ms. Matsui votes aye.
3366 Ms. Castor?
3367 *Ms. Castor. Aye.
3368 *The Clerk. Ms. Castor votes aye.
3369 Mr. Tonko?
3370 *Mr. Tonko. Aye.
3371 *The Clerk. Mr. Tonko votes aye.
3372 Ms. Clarke?

3373 *Ms. Clarke. Aye.
3374 *The Clerk. Ms. Clarke votes aye.
3375 Mr. Ruiz?
3376 *Mr. Ruiz. Aye.
3377 *The Clerk. Mr. Ruiz votes aye.
3378 Mr. Peters?
3379 *Mr. Peters. Aye.
3380 *The Clerk. Mr. Peters votes aye.
3381 Mrs. Dingell?
3382 [No response.]
3383 *The Clerk. Mr. Veasey?
3384 *Mr. Veasey. Aye.
3385 *The Clerk. Mr. Veasey votes aye.
3386 Ms. Kelly?
3387 [No response.]
3388 *The Clerk. Ms. Barragan?
3389 *Ms. Barragan. Aye.
3390 *The Clerk. Ms. Barragan votes aye.
3391 *Ms. Kelly. Aye.
3392 *The Clerk. Ms. Kelly votes aye.
3393 Mr. Soto?
3394 *Mr. Soto. Aye.
3395 *The Clerk. Mr. Soto votes aye.
3396 Ms. Schrier?
3397 *Ms. Schrier. Aye.

3398 *The Clerk. Ms. Schrier votes aye.
3399 Mrs. Trahan?
3400 *Mrs. Trahan. Aye.
3401 *The Clerk. Mrs. Trahan votes aye.
3402 Mrs. Fletcher?
3403 *Mrs. Fletcher. Aye.
3404 *The Clerk. Mrs. Fletcher votes aye.
3405 Ms. Ocasio-Cortez?
3406 *Ms. Ocasio-Cortez. Aye.
3407 *The Clerk. Ms. Ocasio-Cortez votes aye.
3408 Mr. Auchincloss?
3409 *Mr. Auchincloss. Aye.
3410 *The Clerk. Mr. Auchincloss votes aye.
3411 Mr. Carter of Louisiana?
3412 *Mr. Carter of Louisiana. Aye.
3413 *The Clerk. Mr. Carter of Louisiana votes aye.
3414 Mr. Menendez?
3415 *Mr. Menendez. Aye.
3416 *The Clerk. Mr. Menendez votes aye.
3417 Mr. Mullin?
3418 *Mr. Mullin. Aye.
3419 *The Clerk. Mr. Mullin votes aye.
3420 Mr. Landsman?
3421 *Mr. Landsman. Aye.
3422 *The Clerk. Mr. Landsman votes aye.

3423 Ms. McClellan?

3424 *Ms. McClellan. Aye.

3425 *The Clerk. Ms. McClellan votes aye.

3426 Chairman Guthrie?

3427 [No response.]

3428 *Mr. Latta. How is the gentleman from Virginia

3429 recorded?

3430 *Mr. Griffith. No. I mean yes, sorry.

3431 *The Clerk. Mr. Griffith votes aye.

3432 *Mr. Latta. The gentleman from Michigan?

3433 *The Clerk. Mr. James is --

3434 *Mr. James. Aye.

3435 *The Clerk. -- votes aye.

3436 *Mr. Latta. The gentleman from Texas?

3437 *Mr. Weber. Aye.

3438 *The Clerk. Mr. Weber votes aye.

3439 *Mr. Latta. The gentleman from Oregon?

3440 *The Clerk. Mr. Bentz is not recorded.

3441 *Mr. Bentz. Aye.

3442 *The Clerk. Mr. Bentz votes aye.

3443 *Mr. Latta. The gentleman from Idaho?

3444 *Mr. Fulcher. Fulcher is aye.

3445 *The Clerk. Mr. Fulcher votes aye.

3446 *Mr. Latta. The gentlelady from Florida?

3447 *The Clerk. Mrs. Cammack is not recorded.

3448 *Mrs. Cammack. Aye.

3449 *The Clerk. Mrs. Cammack votes aye.

3450 *Mr. Latta. How is the chairman recorded?

3451 *The Chair. Aye.

3452 *The Clerk. Chairman Guthrie votes aye.

3453 *Mr. Latta. The gentleman from Pennsylvania?

3454 *Mr. Joyce. The gentleman is aye.

3455 *The Clerk. Mr. Joyce votes aye.

3456 *Mr. Latta. Are there any other members wishing to

3457 record their vote?

3458 Hearing none, the clerk will report.

3459 *The Chair. Can you do five more minutes? I will be

3460 right back.

3461 *Mr. Latta. Yes, yes.

3462 [Pause.]

3463 *The Clerk. Mr. Chairman, on that vote there were 47

3464 ayes and 0 noes.

3465 *Mr. Latta. Thank you very much. The bill is adopted,

3466 and the clerk -- next, the chair now calls up H.R. 9339 and

3467 asks the clerk to report.

3468 *The Clerk. H.R. 9339, a bill to require the Secretary

3469 of Energy to conduct an assessment --

3470 *Mr. Latta. Without objection, the first reading of the

3471 bill is dispensed with, and the bill will be open for

3472 amendment at any point.

3473 So ordered.

3474 [The bill follows:]

3475

3476 *****COMMITTEE INSERT*****

3477

3478 *Mr. Latta. Does any member seek recognition on the
3479 bill?

3480 For what purpose does the gentlelady from Tennessee's
3481 1st district seek recognition?

3482 *Mrs. Harshbarger. To speak on the bill.

3483 *Mr. Latta. The gentlelady is recognized for five
3484 minutes to speak on the bill.

3485 *Mrs. Harshbarger. Thank you, Mr. Chairman.

3486 Our bulk power supply is aging while energy demand is
3487 skyrocketing. And as we work to bring new generation online,
3488 tools like high-performance computing and AI can help our
3489 existing grid run with greater capacity and reliability.
3490 That is the purpose of my bipartisan legislation, the
3491 Affordable Innovation for the Grid Act, which I introduced
3492 with my colleague, Representative Mullin. It will direct
3493 DoE, in consultation with FERC and NERC, to assess how these
3494 technologies can be deployed to support the bulk power
3495 system.

3496 We are already seeing what is possible because last year
3497 FERC Commissioner Rosner highlighted how one platform was
3498 able to complete an interconnection study in just 10 days.
3499 The manual interconnection study that it was based on took
3500 two years to complete. That is exactly the kind of
3501 efficiency we need to start clearing our backlog to
3502 interconnection queues.

3503 Argonne National Laboratory has also demonstrated how
3504 these tools can support the grid through predictive
3505 maintenance. In one project, Argonne found this approach
3506 reduced total maintenance costs by more than 40 percent and
3507 unnecessary crew visits by more than 60 percent. And by
3508 minimizing downtime and addressing problems before they
3509 escalate, our energy providers can keep the lights on and
3510 plan more effectively for both near and long-term grid needs.

3511 There is enormous potential in these technologies to
3512 help our grid run more efficiently, but we need to get the
3513 details right. A thorough technical assessment from DoE,
3514 FERC, and NERC will be essential to identify where grid
3515 operators and utilities can put these tools to use to
3516 strengthen reliability and affordability for ratepayers.

3517 So I urge all my colleagues to support H.R. 9339, the
3518 Affordable Innovation for the Grid Act.

3519 And with that, Mr. Chairman, I yield back.

3520 *Mr. Latta. The gentlelady yields back. Is there
3521 further discussion?

3522 For what purpose does the gentleman from California's
3523 15th district seek recognition?

3524 *Mr. Mullin. To speak on the bill, Mr. Chair.

3525 *Mr. Latta. The gentleman is recognized for five
3526 minutes to speak on the bill.

3527 *Mr. Mullin. Thank you, Mr. Chair.

3528 Today electricity demand continues to rise, as do bills
3529 for everyday Americans. To protect consumers we need to make
3530 the grid more efficient and get energy connected to the grid
3531 more quickly. I believe we can work towards those goals by
3532 supporting the adoption of leading-edge grid technologies.
3533 That is why I partnered with Representative Harshbarger on
3534 the Affordable Innovation for the Grid Act. This bill would
3535 direct the Department of Energy to study how artificial
3536 intelligence and advanced computing can support the grid.

3537 Right now it takes five years for a new power source to
3538 connect to the grid, but AI can significantly reduce this
3539 timeline without compromising reliability. Every utility in
3540 the country should be figuring out how to responsibly deploy
3541 these technologies. While our committee has missed an
3542 opportunity to mark up Representative Castor's Expediting
3543 Grid Interconnection Procedures Act, which I also support,
3544 the issues facing our grid will not wait. That is why I
3545 encourage my colleagues to support the bill which will spur
3546 innovation for grid efficiency, energy deployment, and lower
3547 costs.

3548 Again, I want to thank Representative Harshbarger for
3549 her leadership and collaboration on this effort.

3550 And with that I yield back.

3551 *Mr. Latta. Thank you very much. The gentleman yields
3552 back. Is there further discussion on the bill?

3553 Are there any amendments on the bill?

3554 Seeing none, the question now occurs on adopting H.R.

3555 9339. A roll call vote has been requested and the clerk will

3556 call the roll.

3557 *The Clerk. Mr. Latta?

3558 *Mr. Latta. Aye.

3559 *The Clerk. Mr. Latta votes aye.

3560 Mr. Griffith?

3561 *Mr. Griffith. Aye.

3562 *The Clerk. Mr. Griffith votes aye.

3563 Mr. Bilirakis?

3564 [No response.]

3565 *The Clerk. Mr. Hudson?

3566 [No response.]

3567 *The Clerk. Mr. Carter of Georgia?

3568 [No response.]

3569 *The Clerk. Mr. Palmer?

3570 [No response.]

3571 *The Clerk. Mr. Dunn?

3572 [No response.]

3573 *The Clerk. Mr. Crenshaw?

3574 [No response.]

3575 *The Clerk. Mr. Joyce?

3576 [No response.]

3577 *The Clerk. Mr. Weber?

3578 [No response.]
3579 *The Clerk. Mr. Allen?
3580 *Mr. Allen. Aye.
3581 *The Clerk. Mr. Allen votes aye.
3582 Mr. Balderson?
3583 [No response.]
3584 *The Clerk. Mr. Fulcher?
3585 *Mr. Balderson. Aye.
3586 *The Clerk. Mr. Balderson votes aye.
3587 Mr. Fulcher?
3588 [No response.]
3589 *The Clerk. Mr. Pfluger?
3590 *Mr. Pfluger. Aye.
3591 *The Clerk. Mr. Pfluger votes aye.
3592 Mrs. Harshbarger?
3593 *Mrs. Harshbarger. Aye.
3594 *The Clerk. Mrs. Harshbarger votes aye.
3595 Mrs. Miller-Meeks?
3596 [No response.]
3597 *The Clerk. Mrs. Cammack?
3598 [No response.]
3599 *The Clerk. Mr. Obernolte?
3600 [No response.]
3601 *The Clerk. Mr. James?
3602 [No response.]

3603 *The Clerk. Mr. Bentz?
3604 [No response.]
3605 *The Clerk. Mrs. Houchin?
3606 *Mrs. Houchin. Aye.
3607 *The Clerk. Mrs. Houchin votes aye.
3608 Mr. Fry?
3609 [No response.]
3610 *The Clerk. Ms. Lee?
3611 *Ms. Lee. Aye.
3612 *The Clerk. Ms. Lee votes aye.
3613 Mr. Langworthy?
3614 *Mr. Langworthy. Aye.
3615 *The Clerk. Mr. Langworthy votes aye.
3616 Mr. Kean?
3617 *Mr. Kean. Aye.
3618 *The Clerk. Mr. Kean votes aye.
3619 Mr. Rulli?
3620 *Mr. Rulli. Aye.
3621 *The Clerk. Mr. Rulli votes aye.
3622 Mr. Evans?
3623 [No response.]
3624 *The Clerk. Mr. Goldman?
3625 [No response.]
3626 *The Clerk. Mrs. Fedorchak?
3627 [No response.]

3628 *The Clerk. Mr. Pallone?
3629 *Mr. Pallone. Aye.
3630 *The Clerk. Mr. Pallone votes aye.
3631 Ms. DeGette?
3632 [No response.]
3633 *The Clerk. Ms. Schakowsky?
3634 *Ms. Schakowsky. Aye.
3635 *The Clerk. Ms. Schakowsky votes aye.
3636 Ms. Matsui?
3637 *Ms. Matsui. Aye.
3638 *The Clerk. Ms. Matsui votes aye.
3639 Ms. Castor?
3640 *Ms. Castor. Aye.
3641 *The Clerk. Ms. Castor votes aye.
3642 Mr. Tonko?
3643 *Mr. Tonko. Aye.
3644 *The Clerk. Mr. Tonko votes aye.
3645 Ms. Clarke?
3646 [No response.]
3647 *The Clerk. Mr. Ruiz?
3648 [No response.]
3649 *The Clerk. Mr. Peters?
3650 *Mr. Peters. Aye.
3651 *The Clerk. Mr. Peters votes aye.
3652 Mrs. Dingell?

3653 [No response.]

3654 *The Clerk. Mr. Veasey?

3655 *Mr. Veasey. Aye.

3656 *The Clerk. Mr. Veasey votes aye.

3657 Ms. Kelly?

3658 *Ms. Kelly. Aye.

3659 *The Clerk. Ms. Kelly votes aye.

3660 Ms. Barragan?

3661 *Ms. Barragan. Aye.

3662 *The Clerk. Ms. Barragan votes aye.

3663 Mr. Soto?

3664 *Mr. Soto. Aye.

3665 *The Clerk. Mr. Soto votes aye.

3666 Ms. Schrier?

3667 *Ms. Schrier. Aye.

3668 *The Clerk. Ms. Schrier votes aye.

3669 Mrs. Trahan?

3670 *Mrs. Trahan. Aye.

3671 *The Clerk. Mrs. Trahan votes aye.

3672 Mrs. Fletcher?

3673 *Mrs. Fletcher. Aye.

3674 *The Clerk. Mrs. Fletcher votes aye.

3675 Ms. Ocasio-Cortez?

3676 *Ms. Ocasio-Cortez. Aye.

3677 *The Clerk. Ms. Ocasio-Cortez votes aye.

3678 Mr. Auchincloss?
3679 *Mr. Auchincloss. Aye.
3680 *The Clerk. Mr. Auchincloss votes aye.
3681 Mr. Carter of Louisiana?
3682 *Mr. Carter of Louisiana. Aye.
3683 *The Clerk. Mr. Carter of Louisiana votes aye.
3684 Mr. Menendez?
3685 *Mr. Menendez. Aye.
3686 *The Clerk. Mr. Menendez votes aye.
3687 Mr. Mullin?
3688 *Mr. Mullin. Aye.
3689 *The Clerk. Mr. Mullin votes aye.
3690 Mr. Landsman?
3691 *Mr. Landsman. Aye.
3692 *The Clerk. Mr. Landsman votes aye.
3693 Ms. McClellan?
3694 *Ms. McClellan. Aye.
3695 *The Clerk. Ms. McClellan votes aye.
3696 Chairman Guthrie?
3697 *The Chair. Aye.
3698 *The Clerk. Chairman Guthrie votes aye.
3699 *Mr. Latta. Are there any other members wishing to be
3700 recognized?
3701 The gentleman from Florida.
3702 *The Clerk. Mr. Bilirakis is not recorded.

3703 *Mr. Bilirakis. Aye.

3704 *The Clerk. Mr. Bilirakis votes aye.

3705 *Mr. Latta. The gentleman from North Carolina?

3706 *Mr. Hudson. Hudson votes aye.

3707 *The Clerk. Mr. Hudson votes aye.

3708 *Mr. Latta. The gentleman from Georgia?

3709 *Mr. Carter of Georgia. Aye.

3710 *The Clerk. Mr. Carter votes aye.

3711 *Mr. Latta. The gentleman from Texas?

3712 *Mr. Weber. Weber votes aye.

3713 *The Clerk. Mr. Weber --

3714 *Mr. Latta. The gentleman from New --

3715 *The Clerk. -- votes aye.

3716 *Mr. Latta. I am sorry, from Pennsylvania.

3717 *Mr. Joyce. Joyce votes aye.

3718 *The Clerk. Mr. Joyce votes aye.

3719 *Mr. Latta. The gentleman from Idaho?

3720 *Mr. Fulcher. Fulcher is aye.

3721 *The Clerk. Mr. Fulcher votes aye.

3722 *Mr. Latta. The gentlelady from New York?

3723 *Ms. Clarke. Yvette Clarke votes aye.

3724 *The Clerk. Ms. Clarke votes aye.

3725 *Mr. Latta. The gentleman from California?

3726 *Mr. Ruiz. Aye.

3727 *The Clerk. Mr. Ruiz votes aye.

3728 *Mr. Latta. The gentlelady from Michigan?
3729 *Mrs. Dingell. Votes aye.
3730 *The Clerk. Mrs. Dingell votes aye.
3731 *Mr. Latta. Oh, I am sorry, the gentleman from Texas?
3732 *Mr. Goldman. Aye.
3733 *The Clerk. Mr. Goldman votes aye.
3734 *Voice. Mr. Kean.
3735 *Mr. Latta. And the gentleman from Michigan?
3736 I am sorry. Oh, I thought you said James. I am sorry.
3737 The gentleman from New Jersey?
3738 [Pause.]
3739 *Mr. Latta. The gentleman from California?
3740 *Mr. Obernolte. Aye.
3741 *The Clerk. Mr. Obernolte votes aye.
3742 *Voice. Mr. Kean.
3743 *Mr. Latta. Is the -- recorded, thank you. Are there
3744 any other members wishing to record their vote?
3745 Is Mr. Kean recorded?
3746 *The Clerk. Yes, Mr. Kean is recorded as aye.
3747 *Mr. Latta. Thank you very much. And the gentleman
3748 from Alabama?
3749 *The Clerk. Mr. Palmer is not recorded.
3750 *Mr. Latta. Yes.
3751 *Mr. Palmer. Aye.
3752 *The Clerk. Mr. Palmer votes aye.

3753 *Mr. Latta. Are any other members wishing to record
3754 their vote?

3755 Hearing none, the clerk will report.

3756 [Pause.]

3757 *The Clerk. Mr. Chairman, on that vote there were 44
3758 ayes and 0 noes.

3759 *Mr. Latta. Thank you very much. The ayes have it.
3760 The bill is adopted.

3761 Clerk, call -- the chair calls up H.R. 6529 and asks the
3762 clerk to report.

3763 *The Clerk. Committee print of H.R. 6529, a bill to
3764 require the Federal Energy Regulatory Commission --

3765 *Mr. Latta. Without objection, the first reading of the
3766 bill is dispensed with, and the bill will be open for
3767 amendment at any point.

3768 So ordered.

3769 [The bill follows:]

3770

3771 *****COMMITTEE INSERT*****

3772

3773 *Mr. Latta. Does anyone seek recognition on the bill?
3774 For what purpose does the gentleman from Ohio's 1st
3775 district seek recognition?

3776 *Mr. Landsman. To speak on the bill.

3777 *Mr. Latta. The gentleman is recognized for five
3778 minutes to speak on the bill.

3779 *Mr. Landsman. Thank you, Mr. Chair.

3780 The Protecting Families from AI Data Centers Energy
3781 Costs Act would require FERC to hold a technical conference
3782 to bring all stakeholders together and produce for us
3783 detailed recommendations, best practices to ensure that
3784 ratepayers are protected, that there isn't a single dime that
3785 they are charged in terms of the data centers' usage of
3786 electricity.

3787 So there, I think, needs to be a lot of work here in
3788 terms of these state regulatory entities and holding and
3789 protecting these communities, ratepayers. But FERC
3790 ultimately has to step up too. I am of the opinion that we
3791 need a national framework, and this gets us to the kind of
3792 Federal leadership that I think most communities are looking
3793 for.

3794 This focuses on costs. There has been a lot of
3795 discussion about the environmental impact. Obviously, that
3796 needs to be taken into account and part of this -- I think
3797 the NDAs have to go. But this is a common-sense approach,

3798 and I appreciate Mr. Griffith for jumping on board. And
3799 hopefully my colleagues will support it.

3800 Again, the bill just requires FERC to bring all of the
3801 key folks together and produce for us detailed
3802 recommendations, best practices to ensure that rising energy
3803 costs from data centers aren't passed on to our communities
3804 or ratepayers.

3805 Thank you, I yield back.

3806 *Mr. Latta. Thank you. The gentleman yields back. For
3807 what purpose does the gentleman from Virginia's 9th district
3808 seek recognition?

3809 *Mr. Griffith. Speaking on the measure.

3810 *Mr. Latta. The gentleman is recognized for five
3811 minutes to speak on the bill.

3812 *Mr. Griffith. Thank you, Mr. Chairman. I am proud to
3813 be the Republican co-lead on this timely bill of Mr.
3814 Landsman's.

3815 The bill directs the convening of a comprehensive
3816 technical conference at the Federal Energy Regulatory
3817 Commission on ensuring that large loads like data centers pay
3818 their fair share to connect to the electric grid. The bill
3819 reinforces the principle that data centers, not household
3820 ratepayers -- I always refer to them on the stump as ma and
3821 pa farmer because agriculture is a big deal in my district --
3822 they don't -- that farmers and the average household

3823 ratepayers do not need to pay for new transmission lines and
3824 substations as they sign up to connect to the grid -- as the
3825 data centers sign up to connect to the grid and begin ramping
3826 up power use.

3827 FERC and state utility commissioners are already
3828 beginning to -- the work of creating parameters on electric
3829 rate arrangements for large loads. As FERC begins its
3830 proceedings to examine current transmission rules in light of
3831 more large loads connecting to the electric grid under the
3832 Federal Power Act, it is imperative that the commissioners
3833 keep household ratepayers top of their mind.

3834 Just like any other any other businesses, data centers
3835 should be able to connect to the electric grid. However, the
3836 scale of this electric demand over the past few years has
3837 called into question long-time electric rate structures and
3838 rules on how the cost of electric infrastructure should be
3839 charged to the ratepayers. This bill is going -- is about
3840 giving all interested parties, including state regulators and
3841 consumers, a seat at the table as Federal regulators sort out
3842 the best way to make sure power costs are carefully
3843 distributed under the Federal Power Act -- again, as Mr.
3844 Landsman said, to protect the ratepayer, the average
3845 householder.

3846 I believe that this legislation will provide valuable
3847 direction to FERC on their deliberations on this issue and

3848 will help elevate the questions and concerns that I hear
3849 regularly from my constituents -- and I am sure many of you
3850 all are, as well -- on what data centers might mean for their
3851 electric bills.

3852 In addition to informing FERC's proceedings, I believe
3853 that the report required by this bill and the report to this
3854 committee will be useful for informing Congress's work on the
3855 issue as we go forward.

3856 I am glad to be the Republican co-lead on Congressman
3857 Landsman's bill, and I urge all of my colleagues to vote in
3858 favor of reporting this bill.

3859 Thank you so much, Mr. Chairman, and with that I yield
3860 back.

3861 *The Chair. [Presiding.] The gentleman yields back. Is
3862 there any further discussion on the bill?

3863 Seeing none, are there any amendments to the bill?

3864 Seeing none, the question now occurs on adopting H.R.
3865 6529. As amended, right? No amendment. A roll call has
3866 been requested and the clerk will call the roll.

3867 *The Clerk. Mr. Latta?

3868 *Mr. Latta. Aye.

3869 *The Clerk. Mr. Latta votes aye.

3870 Mr. Griffith?

3871 *Mr. Griffith. Aye.

3872 *The Clerk. Mr. Griffith votes aye.

3873 Mr. Bilirakis?
3874 [No response.]
3875 *The Clerk. Mr. Hudson?
3876 [No response.]
3877 *The Clerk. Mr. Carter of Georgia?
3878 [No response.]
3879 *The Clerk. Mr. Palmer?
3880 [No response.]
3881 *The Clerk. Mr. Dunn?
3882 [No response.]
3883 *The Clerk. Mr. Crenshaw?
3884 [No response.]
3885 *The Clerk. Mr. Joyce?
3886 *Mr. Joyce. Aye.
3887 *The Clerk. Mr. Joyce votes aye.
3888 Mr. Weber?
3889 *Mr. Weber. Aye.
3890 *The Clerk. Mr. Weber votes aye.
3891 Mr. Allen?
3892 *Mr. Allen. Aye.
3893 *The Clerk. Mr. Allen votes aye.
3894 Mr. Balderson?
3895 [No response.]
3896 *The Clerk. Mr. Balderson?
3897 *Mr. Balderson. Aye.

3898 *The Clerk. Mr. Balderson votes aye.
3899 Mr. Fulcher?
3900 *Mr. Fulcher. Fulcher is aye.
3901 *The Clerk. Mr. Fulcher votes aye.
3902 Mr. Pfluger?
3903 [No response.]
3904 *The Clerk. Mrs. Harshbarger?
3905 *Mrs. Harshbarger. Aye.
3906 *The Clerk. Mrs. Harshbarger votes aye.
3907 Mrs. Miller-Meeks?
3908 [No response.]
3909 *The Clerk. Mrs. Cammack?
3910 [No response.]
3911 *The Clerk. Mr. Obernolte?
3912 *Mr. Obernolte. Aye.
3913 *The Clerk. Mr. Obernolte votes aye.
3914 Mr. James?
3915 [No response.]
3916 *The Clerk. Mr. Bentz?
3917 [No response.]
3918 *The Clerk. Mrs. Houchin?
3919 [No response.]
3920 *The Clerk. Mr. Fry?
3921 [No response.]
3922 *The Clerk. Ms. Lee?

3923 *Ms. Lee. Aye.
3924 *The Clerk. Ms. Lee votes aye.
3925 Mr. Langworthy?
3926 [No response.]
3927 *The Clerk. Mr. Kean?
3928 *Mr. Kean. Aye.
3929 *The Clerk. Mr. Kean votes aye.
3930 Mr. Rulli?
3931 *Mr. Rulli. Aye.
3932 *The Clerk. Mr. Rulli votes aye.
3933 Mr. Evans?
3934 [No response.]
3935 *The Clerk. Mr. Goldman?
3936 *Mr. Goldman. Aye.
3937 *The Clerk. Mr. Goldman votes aye.
3938 Mrs. Fedorchak?
3939 [No response.]
3940 *The Clerk. Mr. Pallone?
3941 *Mr. Pallone. Aye.
3942 *The Clerk. Mr. Pallone votes aye.
3943 Ms. DeGette?
3944 [No response.]
3945 *The Clerk. Ms. Schakowsky?
3946 *Ms. Schakowsky. Yes.
3947 *The Clerk. Ms. Schakowsky votes aye.

3948 Ms. Matsui?
3949 *Ms. Matsui. Aye.
3950 *The Clerk. Ms. Matsui votes aye.
3951 Ms. Castor?
3952 *Ms. Castor. Aye.
3953 *The Clerk. Ms. Castor votes aye.
3954 Mr. Tonko?
3955 *Mr. Tonko. Aye.
3956 *The Clerk. Mr. Tonko votes aye.
3957 Ms. Clarke?
3958 [No response.]
3959 *The Clerk. Ms. Clarke?
3960 *Ms. Clarke. Aye.
3961 *The Clerk. Ms. Clarke votes aye.
3962 Mr. Ruiz?
3963 *Mr. Ruiz. Aye.
3964 *The Clerk. Mr. Ruiz votes aye.
3965 Mr. Peters?
3966 *Mr. Peters. Aye.
3967 *The Clerk. Mr. Peters votes aye.
3968 Mrs. Dingell?
3969 *Mrs. Dingell. Aye.
3970 *The Clerk. Mrs. Dingell votes aye.
3971 Mr. Veasey?
3972 *Mr. Veasey. Aye.

3973 *The Clerk. Mr. Veasey votes aye.
3974 Ms. Kelly?
3975 *Ms. Kelly. Aye.
3976 *The Clerk. Ms. Kelly votes aye.
3977 Ms. Barragan?
3978 *Ms. Barragan. Aye.
3979 *The Clerk. Ms. Barragan votes aye.
3980 Mr. Soto?
3981 *Mr. Soto. Aye.
3982 *The Clerk. Mr. Soto votes aye.
3983 Ms. Schrier?
3984 *Ms. Schrier. Aye.
3985 *The Clerk. Ms. Schrier votes aye.
3986 Mrs. Trahan?
3987 *Mrs. Trahan. Aye.
3988 *The Clerk. Mrs. Trahan votes aye.
3989 Mrs. Fletcher?
3990 *Mrs. Fletcher. Aye.
3991 *The Clerk. Mrs. Fletcher votes aye.
3992 Ms. Ocasio-Cortez?
3993 *Ms. Ocasio-Cortez. Aye.
3994 *The Clerk. Ms. Ocasio-Cortez votes aye.
3995 Mr. Auchincloss?
3996 *Mr. Auchincloss. Aye.
3997 *The Clerk. Mr. Auchincloss votes aye.

3998 Mr. Carter of Louisiana?
3999 [No response.]
4000 *The Clerk. Mr. Carter of Louisiana?
4001 *Mr. Carter of Louisiana. Aye.
4002 *The Clerk. Mr. Carter of Louisiana votes aye.
4003 Mr. Menendez?
4004 *Mr. Menendez. Aye.
4005 *The Clerk. Mr. Menendez votes aye.
4006 Mr. Mullin?
4007 *Mr. Mullin. Aye.
4008 *The Clerk. Mr. Mullin votes aye.
4009 Mr. Landsman?
4010 *Mr. Landsman. Aye.
4011 *The Clerk. Mr. Landsman votes aye.
4012 Ms. McClellan?
4013 *Ms. McClellan. Aye.
4014 *The Clerk. Ms. McClellan votes aye.
4015 Chairman Guthrie?
4016 *The Chair. Aye.
4017 *The Clerk. Chairman Guthrie votes aye.
4018 *The Chair. All right. Bilirakis?
4019 *The Clerk. Mr. Bilirakis is not recorded.
4020 *Mr. Bilirakis. Votes aye.
4021 *The Clerk. Mr. Bilirakis --
4022 *The Chair. Carter, Georgia.

4023 *Mr. Carter of Georgia. Aye.
4024 *The Clerk. Mr. Carter of Georgia votes aye.
4025 *The Chair. Mr. Palmer?
4026 *The Clerk. Mr. Palmer is not recorded.
4027 *Mr. Palmer. Aye.
4028 *The Clerk. Mr. Palmer votes aye.
4029 *The Chair. Mr. Langworthy?
4030 *Mr. Langworthy. Aye.
4031 *The Clerk. Mr. Langworthy votes aye.
4032 *The Chair. Mr. James?
4033 *The Clerk. Mr. James --
4034 *Mr. James. Aye.
4035 *The Clerk. -- votes aye.
4036 *The Chair. Mrs. Cammack?
4037 *The Clerk. Mrs. Cammack is not recorded.
4038 *Mrs. Cammack. Aye.
4039 *The Clerk. Mrs. Cammack votes aye.
4040 *The Chair. Mr. Pfluger?
4041 *Mr. Pfluger. Aye.
4042 *The Clerk. Mr. Pfluger votes aye.
4043 *The Chair. You are good on your side? Okay.
4044 Is anyone else seeking recognition to answer the roll?
4045 Seeing none, the clerk will report.
4046 [Pause.]
4047 *The Clerk. Mr. Chairman, on that vote there were 44

4048 ayes and 0 noes.

4049 *The Chair. The ayes have it, and the bill is adopted.

4050 The chair calls up H.R. 9617 and asks the clerk to
4051 report.

4052 *The Clerk. H.R. 9617, a bill to amend the Solid Waste
4053 Disposal Act to direct the --

4054 *The Chair. Without objection, the first reading of the
4055 bill is dispensed with, and the bill will be open for
4056 amendment at any point.

4057 So ordered.

4058 [The bill follows:]

4059

4060 *****COMMITTEE INSERT*****

4061

4062 *The Chair. Does anyone seek to be recognized on the
4063 bill?

4064 For what purpose does the gentleman from Alabama seek to
4065 be recognized?

4066 *Mr. Palmer. Thank you, Mr. Chairman. I would like to
4067 speak in support of my bill, H.R. --

4068 *The Chair. You are recognized for five minutes to
4069 speak on the bill.

4070 *Mr. Palmer. Thank you, Mr. Chairman.

4071 The Coordinating and Harnessing America's Recovery
4072 Minerals, or CHARM Act, as I discussed yesterday, China has
4073 made a calculated, concerted effort to control the supply
4074 chains of important materials, and have already demonstrated
4075 their willingness to exploit our vulnerabilities. This
4076 problem is too grave to ignore, and solving it requires us to
4077 leverage the expertise of all of our Federal agencies, and
4078 this necessitates coordinated action across agencies.

4079 Throughout this Congress the Subcommittee on Environment
4080 has explored opportunities to recover valuable minerals from
4081 legacy mine sites, coal combustion residuals, electronics
4082 waste, and lithium ion batteries. We have a wealth of non-
4083 traditional critical mineral sources already within our
4084 borders, but we need to implement an intentional strategy to
4085 take advantage of these sources and to identify and remove
4086 unnecessary regulatory barriers that stifle innovation and

4087 deter investment.

4088 The United States has already demonstrated its ability
4089 to scale up efforts to recover valuable materials. For
4090 example, highlighted by the International Energy Agency in a
4091 2024 report, aluminum supply shortages associated with World
4092 War II drove increased attention to organized aluminum
4093 recycling efforts. In 2024 the United States had a
4094 significantly higher share of secondary aluminum supply as a
4095 percentage of its total supply other -- than other advanced
4096 economies.

4097 To further these efforts, this legislation directs the
4098 Environmental Protection Agency, in consultation with other
4099 Federal agencies, to develop and carry out a national
4100 critical mineral recovery strategy. This legislation directs
4101 EPA to identify programs both within that agency and within
4102 others that relate to critical mineral recovery. In
4103 formulating this strategy, EPA will identify barriers to
4104 recovering critical minerals from discarded materials,
4105 identify discarded materials that could serve as sources of
4106 recovered critical minerals, and evaluate the role of
4107 recovered mineral -- critical minerals in strengthening our
4108 domestic supply chains.

4109 I want to thank my Democratic colleague, my friend, Mr.
4110 Tonko, the ranking member of the Subcommittee on Environment,
4111 for joining me in leading this legislation. I am proud of

4112 the bipartisan work we have done so far this Congress, and
4113 this bill is a great example. I encourage my colleagues to
4114 support this bipartisan legislation.

4115 Thank you, Mr. Chairman. I yield back.

4116 *The Chair. The gentleman yields back. Is there a
4117 discussion on the bill?

4118 The gentleman from New York is recognized for five
4119 minutes to speak on the bill.

4120 *Mr. Tonko. Thank you, Mr. Chair. I move to strike the
4121 last word.

4122 *The Chair. The gentleman is recognized to speak on the
4123 bill.

4124 *Mr. Tonko. Last week the CHARM Act was advanced by the
4125 Environment Subcommittee. I thank and reiterate my gratitude
4126 to Chair Palmer for leading us on this bill. I appreciate
4127 his work and the bipartisan spirit that we both lent to this
4128 bill.

4129 The CHARM Act would direct EPA to develop a national
4130 strategy to support critical mineral recovery. There are
4131 significant amounts of discarded materials that have
4132 potential to be transformed into valuable sources of domestic
4133 critical minerals. But those materials often require
4134 collection, recycling, and perhaps reprocessing. And for a
4135 wide variety of reasons, these materials are often ending up
4136 in landfills rather than being reused.

4137 EPA is in a great position to examine these potential
4138 reasons and to determine where regulatory, technological, and
4139 economic barriers exist. It is my hope that this strategy
4140 will build upon EPA's existing efforts to develop a framework
4141 for end-of-life management of batteries to result in the
4142 responsible collection, the reuse, and recycling of these
4143 mineral-rich technologies.

4144 I do think we can all agree that our critical minerals
4145 supply chain challenges are significant, and I am glad to see
4146 a bipartisan embrace of the role material recovery can play
4147 in meeting our demands. So I thank the majority and minority
4148 staff for working together on this bill, and I encourage
4149 members to support it.

4150 And with that, Mr. Chair, I thank you and yield back.

4151 *The Chair. The gentleman yields back. Is there
4152 further discussion on the bill?

4153 The gentleman from Florida? The gentleman from Florida
4154 is recognized for five minutes to speak on the bill.

4155 *Mr. Soto. Thank you, Chairman. We heard these
4156 bipartisan bills in our subcommittee just a week or so ago.
4157 Critical minerals are in just about everything these days:
4158 cell phones, computers, EVs, hybrids, solar panels,
4159 electronics, and more. Mining is one way to get them,
4160 imports is another. But that is becoming increasingly
4161 difficult, especially with our rival, China, making a lot of

4162 those -- processing a lot of those critical minerals. And so
4163 recycling has to be part of the equation: landfills, coal,
4164 ash, other waste, all rich in critical minerals.

4165 It is essential that we protect public health, first and
4166 foremost. Local communities need to have a big part of this
4167 as well. Using these minerals only once, though, would be a
4168 waste. And so the CHARM Act and the EMRTAI are both
4169 important progress. One would develop a national critical
4170 mineral recovery strategy and the other improves technology
4171 to extract and recycle these critical minerals. So I
4172 encourage my colleagues to vote for this important piece of
4173 legislation, and let's make sure we are improving our ability
4174 to produce and recycle critical minerals at home.

4175 *The Chair. The gentleman yields back. Is there
4176 further discussion on the bill?

4177 Seeing none, are there any amendments to the bill?

4178 Seeing none, the question occurs on adopting H.R. 9617.
4179 A roll call has been requested and the clerk will call the
4180 roll.

4181 *The Clerk. Mr. Latta?

4182 [No response.]

4183 *The Clerk. Mr. Latta?

4184 *Mr. Latta. Aye.

4185 *The Clerk. Mr. Latta votes aye.

4186 Mr. Griffith?

4187 [No response.]
4188 *The Clerk. Mr. Bilirakis?
4189 [No response.]
4190 *The Clerk. Mr. Hudson?
4191 [No response.]
4192 *The Clerk. Mr. Carter of Georgia?
4193 *Mr. Carter of Georgia. Aye.
4194 *The Clerk. Mr. Carter of Georgia votes aye.
4195 Mr. Palmer?
4196 *Mr. Palmer. Aye.
4197 *The Clerk. Mr. Palmer votes aye.
4198 Mr. Dunn?
4199 [No response.]
4200 *The Clerk. Mr. Crenshaw?
4201 [No response.]
4202 *The Clerk. Mr. Joyce?
4203 *Mr. Joyce. Aye.
4204 *The Clerk. Mr. Joyce votes aye.
4205 Mr. Weber?
4206 *Mr. Weber. Aye.
4207 *The Clerk. Mr. Weber votes aye.
4208 Mr. Allen?
4209 *Mr. Allen. Aye.
4210 *The Clerk. Mr. Allen votes aye.
4211 Mr. Balderson?

4212 *Mr. Balderson. Aye.
4213 *The Clerk. Mr. Balderson votes aye.
4214 Mr. Fulcher?
4215 *Mr. Fulcher. Fulcher is aye.
4216 *The Clerk. Mr. Fulcher votes aye.
4217 Mr. Pfluger?
4218 *Mr. Pfluger. Aye.
4219 *The Clerk. Mr. Pfluger votes aye.
4220 Mrs. Harshbarger?
4221 *Mrs. Harshbarger. Aye.
4222 *The Clerk. Mrs. Harshbarger votes aye.
4223 Mrs. Miller-Meeks?
4224 *Mrs. Miller-Meeks. Aye.
4225 *The Clerk. Mrs. Miller-Meeks votes aye.
4226 Mrs. Cammack?
4227 *Mrs. Cammack. Aye.
4228 *The Clerk. Mrs. Cammack votes aye.
4229 Mr. Obernolte?
4230 *Mr. Obernolte. Aye.
4231 *The Clerk. Mr. Obernolte votes aye.
4232 Mr. James?
4233 [No response.]
4234 *The Clerk. Mr. Bentz?
4235 [No response.]
4236 *The Clerk. Mrs. Houchin?

4237 [No response.]
4238 *The Clerk. Mr. Fry?
4239 *Mrs. Houchin. Aye.
4240 *The Clerk. Mrs. Houchin votes aye.
4241 Mr. Fry?
4242 [No response.]
4243 *The Clerk. Ms. Lee?
4244 *Ms. Lee. Aye.
4245 *The Clerk. Ms. Lee votes aye.
4246 Mr. Langworthy?
4247 *Mr. Langworthy. Aye.
4248 *The Clerk. Mr. Langworthy votes aye.
4249 Mr. Kean?
4250 *Mr. Kean. Aye.
4251 *The Clerk. Mr. Kean votes aye.
4252 Mr. Rulli?
4253 *Mr. Rulli. Aye.
4254 *The Clerk. Mr. Rulli votes aye.
4255 Mr. Evans?
4256 *Mr. Evans. Aye.
4257 *The Clerk. Mr. Evans votes aye.
4258 Mr. Goldman?
4259 *Mr. Goldman. Aye.
4260 *The Clerk. Mr. Goldman votes aye.
4261 Mrs. Fedorchak?

4262 [No response.]

4263 *The Clerk. Mr. Pallone?

4264 *Mr. Pallone. Aye.

4265 *The Clerk. Mr. Pallone votes aye.

4266 Ms. DeGette?

4267 [No response.]

4268 *The Clerk. Ms. Schakowsky?

4269 *Ms. Schakowsky. Yes.

4270 *The Clerk. Ms. Schakowsky votes aye.

4271 Ms. Matsui?

4272 *Ms. Matsui. Aye.

4273 *The Clerk. Ms. Matsui votes aye.

4274 Ms. Castor?

4275 *Ms. Castor. Aye.

4276 *The Clerk. Ms. Castor votes aye.

4277 Mr. Tonko?

4278 *Mr. Tonko. Aye.

4279 *The Clerk. Mr. Tonko votes aye.

4280 Ms. Clarke?

4281 [No response.]

4282 *The Clerk. Mr. Ruiz?

4283 *Mr. Ruiz. Aye.

4284 *The Clerk. Mr. Ruiz votes aye.

4285 Mr. Peters?

4286 *Mr. Peters. Aye.

4287 *The Clerk. Mr. Peters votes aye.
4288 Mrs. Dingell?
4289 *Mrs. Dingell. Aye.
4290 *The Clerk. Mrs. Dingell votes aye.
4291 Mr. Veasey?
4292 [No response.]
4293 *The Clerk. Ms. Kelly?
4294 *Ms. Kelly. Aye.
4295 *The Clerk. Ms. Kelly votes aye.
4296 Ms. Barragan?
4297 *Mr. Veasey. Aye.
4298 *The Clerk. Mr. Veasey votes aye.
4299 Ms. Barragan?
4300 *Ms. Barragan. Aye.
4301 *The Clerk. Ms. Barragan votes aye.
4302 Mr. Soto?
4303 *Mr. Soto. Aye.
4304 *The Clerk. Mr. Soto votes aye.
4305 Ms. Schrier?
4306 *Ms. Schrier. Aye.
4307 *The Clerk. Ms. Schrier votes aye.
4308 Mrs. Trahan?
4309 *Mrs. Trahan. Aye.
4310 *The Clerk. Mrs. Trahan votes aye.
4311 Mrs. Fletcher?

4312 *Mrs. Fletcher. Aye.
4313 *The Clerk. Mrs. Fletcher votes aye.
4314 Ms. Ocasio-Cortez?
4315 *Ms. Ocasio-Cortez. Aye.
4316 *The Clerk. Ms. Ocasio-Cortez votes aye.
4317 Mr. Auchincloss?
4318 *Mr. Auchincloss. Aye.
4319 *The Clerk. Mr. Auchincloss votes aye.
4320 Mr. Carter of Louisiana?
4321 *Mr. Carter of Louisiana. Aye.
4322 *The Clerk. Mr. Carter of Louisiana votes aye.
4323 Mr. Menendez?
4324 *Mr. Menendez. Aye.
4325 *The Clerk. Mr. Menendez votes aye.
4326 Mr. Mullin?
4327 *Mr. Mullin. Aye.
4328 *The Clerk. Mr. Mullin votes aye.
4329 Mr. Landsman?
4330 *Mr. Landsman. Aye.
4331 *The Clerk. Mr. Landsman votes aye.
4332 Ms. McClellan?
4333 *Ms. McClellan. Aye.
4334 *The Clerk. Ms. McClellan votes aye.
4335 Chairman Guthrie?
4336 *The Chair. Aye.

4337 *The Clerk. Chairman Guthrie votes aye.
4338 *The Chair. Does anyone seek to --
4339 *The Clerk. Mr. Griffith?
4340 *Mr. Griffith. Aye.
4341 *The Clerk. Mr. Griffith votes aye.
4342 *The Chair. Mr. Bilirakis?
4343 *Mr. Bilirakis. Aye.
4344 *The Clerk. Mr. Bilirakis votes aye.
4345 *The Chair. Mr. Hudson?
4346 *Mr. Hudson. Hudson votes aye.
4347 *The Clerk. Mr. Hudson votes aye.
4348 *The Chair. Ms. Clarke?
4349 *The Clerk. Ms. Clarke is not recorded.
4350 *Ms. Clarke. Aye.
4351 *The Clerk. Ms. Clarke votes aye.
4352 [Pause.]
4353 *The Clerk. Mr. Chairman, on that vote there were 47
4354 ayes and 0 noes.
4355 *The Chair. The ayes have it, and the bill is adopted.
4356 The chair calls up H.R. 9616, and asks the clerk to
4357 report.
4358 *The Clerk. H.R. 9616, a bill to --
4359 *The Chair. Without objection, the first reading of the
4360 bill is dispensed with, and the bill will be open for
4361 amendment at any point.

4362 So ordered.

4363 [The bill follows:]

4364

4365 *****COMMITTEE INSERT*****

4366

4367 *The Chair. Does anyone seek to be recognized on the
4368 bill?

4369 The gentleman from Texas is recognized for five minutes
4370 to speak on the bill.

4371 *Mr. Pfluger. Thank you, Mr. Chairman, and I do, in
4372 fact, speak in support of my bill, H.R. 9616, the
4373 Environmental Monitoring and Remediation Technology
4374 Assessment Initiative, or EMRTAI, Authorization Act of 2026.

4375 Critical materials are essential to some of the most
4376 important technologies and products in the communications,
4377 energy, defense, and transportation sectors. However, their
4378 supply chains are vulnerable to disruption, and we rely on
4379 other nations, including adversaries such as China, for many
4380 of these. China is currently responsible for over 70 percent
4381 of global rare earth metal production, and refines up to 87
4382 percent of the world's supply of critical minerals. Unless
4383 we develop more domestic sources for critical materials, we
4384 will remain at the mercy of our enemies.

4385 Fortunately, cutting-edge technologies are emerging to
4386 identify and take advantage of unconventional sources of
4387 critical minerals right here at home. In my home state of
4388 Texas, researchers and companies are exploring ways to
4389 recover lithium and other critical minerals from produced
4390 water generated during oil and gas production. The Permian
4391 Basin alone generates millions of barrels of produced water

4392 every day, one of the largest produced water streams in the
4393 world, and the sheer volume of that water presents challenges
4394 but also creates an opportunity to recover valuable critical
4395 minerals from a resource that has historically been treated
4396 as a waste stream.

4397 There are thousands of contaminated sites across the
4398 United States, including over 1,300 of the EPA's national
4399 priority list of the country's most contaminated sites.
4400 Additionally, on Federal lands alone the Federal Government
4401 has spent over \$100 million remediating contamination from
4402 abandoned hardrock mine sites. However, while these sites
4403 are a threat to health and to the environment, they can also
4404 be potential sources of critical materials.

4405 The EMRTAI Authorization Act of 2026 directs EPA to
4406 stand up a program to support methods to identify and recover
4407 critical materials at these sites, contributing to the
4408 development of new domestic sources and encouraging the
4409 remediation of these sites. EPA already has experience
4410 funding such projects. Addressing our supply chain
4411 vulnerability is a daunting challenge, but creative solutions
4412 that leverage technological innovation play a major role in
4413 solving it.

4414 I am grateful that we could work across the aisle to
4415 advance this legislation, and I specifically thank my
4416 colleague from Ohio, Representative Landsman, for joining me

4417 in leading this endeavor. I encourage my colleagues to
4418 support this bipartisan legislation.

4419 And I yield back.

4420 *The Chair. The gentleman yields back. The gentleman
4421 from -- is there anyone seeking recognition to speak on the
4422 bill?

4423 The gentleman from Ohio is recognized for five minutes
4424 to speak on the bill.

4425 *Mr. Landsman. Thank you, Mr. Chairman. As Mr. Pfluger
4426 said, the bill would stand up a grant program to identify and
4427 recover critical minerals at contaminated sites.

4428 There are countless abandoned mines, Superfund and other
4429 industrial sites across the country. And while we clean them
4430 up through public funds, we can also help to replenish our
4431 domestic supply of critical minerals for clean and cheap
4432 renewable energy. This program would give a critical
4433 lifeline to entities that are working on new and innovative
4434 technologies to extract critical minerals from contaminated
4435 sites. It will help them to advance their technologies while
4436 getting both critical minerals and contamination out of these
4437 sites.

4438 I urge my colleagues to support this bill, and with that
4439 I yield back.

4440 *The Chair. The gentleman yields back. Is there
4441 further discussion on the bill?

4442 Seeing none, are there any amendments to the bill?

4443 Seeing none, the question now occurs on adopting H.R.

4444 9616. A roll call has been requested and the clerk will call
4445 the roll.

4446 *The Clerk. Mr. Latta?

4447 [No response.]

4448 *The Clerk. Mr. Griffith?

4449 [No response.]

4450 *The Clerk. Mr. Bilirakis?

4451 *Mr. Bilirakis. Yes.

4452 *The Clerk. Mr. Bilirakis votes aye.

4453 Mr. Hudson?

4454 *Mr. Hudson. Aye.

4455 *The Clerk. Mr. Hudson votes aye.

4456 Mr. Carter of Georgia?

4457 [No response.]

4458 *The Clerk. Mr. Palmer?

4459 [No response.]

4460 *The Clerk. Mr. Dunn?

4461 [No response.]

4462 *The Clerk. Mr. Crenshaw?

4463 [No response.]

4464 *The Clerk. Mr. Joyce?

4465 [No response.]

4466 *The Clerk. Mr. Weber?

4467 *Mr. Weber. Aye.
4468 *The Clerk. Mr. Weber votes aye.
4469 Mr. Allen?
4470 *Mr. Allen. Aye.
4471 *The Clerk. Mr. Allen votes aye.
4472 Mr. Balderson?
4473 *Mr. Balderson. Aye.
4474 *The Clerk. Mr. Balderson votes aye.
4475 Mr. Fulcher?
4476 *Mr. Fulcher. Fulcher is aye.
4477 *The Clerk. Mr. Fulcher votes aye.
4478 Mr. Pfluger?
4479 *Mr. Pfluger. Aye.
4480 *The Clerk. Mr. Pfluger votes aye.
4481 Mrs. Harshbarger?
4482 *Mrs. Harshbarger. Aye.
4483 *The Clerk. Mrs. Harshbarger votes aye.
4484 Mrs. Miller-Meeks?
4485 *Mrs. Miller-Meeks. Yes.
4486 *The Clerk. Mrs. Miller-Meeks votes aye.
4487 Mrs. Cammack?
4488 *Mrs. Cammack. Aye.
4489 *The Clerk. Mrs. Cammack votes aye.
4490 Mr. Obernolte?
4491 *Mr. Obernolte. Aye.

4492 *The Clerk. Mr. Obernolte votes aye.
4493 Mr. James?
4494 *Mr. James. Aye.
4495 *The Clerk. Mr. James votes aye.
4496 Mr. Bentz?
4497 [No response.]
4498 *The Clerk. Mrs. Houchin?
4499 *Mrs. Houchin. Aye.
4500 *The Clerk. Mrs. Houchin votes aye.
4501 Mr. Fry?
4502 [No response.]
4503 *The Clerk. Ms. Lee?
4504 *Ms. Lee. Aye.
4505 *The Clerk. Ms. Lee votes aye.
4506 Mr. Langworthy?
4507 *Mr. Langworthy. Aye.
4508 *The Clerk. Mr. Langworthy votes aye.
4509 Mr. Kean?
4510 *Mr. Kean. Aye.
4511 *The Clerk. Mr. Kean votes aye.
4512 Mr. Rulli?
4513 *Mr. Rulli. Aye.
4514 *The Clerk. Mr. Rulli votes aye.
4515 Mr. Evans?
4516 [No response.]

4517 *The Clerk. Mr. Goldman?
4518 [No response.]
4519 *The Clerk. Mrs. Fedorchak?
4520 [No response.]
4521 *The Clerk. Mr. Pallone?
4522 *Mr. Pallone. Aye.
4523 *The Clerk. Mr. Pallone votes aye.
4524 Ms. DeGette?
4525 [No response.]
4526 *The Clerk. Ms. Schakowsky?
4527 *Ms. Schakowsky. Aye.
4528 *The Clerk. Ms. Schakowsky votes aye.
4529 Ms. Matsui?
4530 *Ms. Matsui. Aye.
4531 *The Clerk. Ms. Matsui votes aye.
4532 Ms. Castor?
4533 *Ms. Castor. Aye.
4534 *The Clerk. Ms. Castor votes aye.
4535 Mr. Tonko?
4536 *Mr. Tonko. Aye.
4537 *The Clerk. Mr. Tonko votes aye.
4538 Ms. Clarke?
4539 *Ms. Clarke. Aye.
4540 *The Clerk. Ms. Clarke votes aye.
4541 Mr. Ruiz?

4542 *Mr. Ruiz. Aye.
4543 *The Clerk. Mr. Ruiz votes aye.
4544 Mr. Peters?
4545 *Mr. Peters. Aye.
4546 *The Clerk. Mr. Peters votes aye.
4547 Mrs. Dingell?
4548 *Mrs. Dingell. Aye.
4549 *The Clerk. Mrs. Dingell votes aye.
4550 Mr. Veasey?
4551 *Mr. Veasey. Aye.
4552 *The Clerk. Mr. Veasey votes aye.
4553 Ms. Kelly?
4554 *Ms. Kelly. Aye.
4555 *The Clerk. Ms. Kelly votes aye.
4556 Ms. Barragan?
4557 *Ms. Barragan. Aye.
4558 *The Clerk. Ms. Barragan votes aye.
4559 Mr. Soto?
4560 *Mr. Soto. Aye.
4561 *The Clerk. Mr. Soto votes aye.
4562 Ms. Schrier?
4563 *Ms. Schrier. Aye.
4564 *The Clerk. Ms. Schrier votes aye.
4565 Mrs. Trahan?
4566 *Mrs. Trahan. Aye.

4567 *The Clerk. Mrs. Trahan votes aye.
4568 Mrs. Fletcher?
4569 *Mrs. Fletcher. Aye.
4570 *The Clerk. Mrs. Fletcher votes aye.
4571 Ms. Ocasio-Cortez?
4572 *Ms. Ocasio-Cortez. Aye.
4573 *The Clerk. Ms. Ocasio-Cortez votes aye.
4574 Mr. Auchincloss?
4575 *Mr. Auchincloss. Aye.
4576 *The Clerk. Mr. Auchincloss votes aye.
4577 Mr. Carter of Louisiana?
4578 *Mr. Carter of Louisiana. Aye.
4579 *The Clerk. Mr. Carter of Louisiana votes aye.
4580 Mr. Menendez?
4581 *Mr. Menendez. Aye.
4582 *The Clerk. Mr. Menendez votes aye.
4583 Mr. Mullin?
4584 *Mr. Mullin. Aye.
4585 *The Clerk. Mr. Mullin votes aye.
4586 Mr. Landsman?
4587 *Mr. Landsman. Aye.
4588 *The Clerk. Mr. Landsman votes aye.
4589 Ms. McClellan?
4590 *Ms. McClellan. Aye.
4591 *The Clerk. Ms. McClellan votes aye.

4592 Chairman Guthrie?
4593 *The Chair. Aye.
4594 *The Clerk. Chairman Guthrie votes aye.
4595 *The Chair. Mr. Latta?
4596 *The Clerk. Mr. Latta is not recorded.
4597 *Mr. Latta. Aye.
4598 *The Clerk. Mr. Latta votes aye.
4599 *The Chair. Mr. Carter?
4600 *Mr. Carter of Georgia. Aye.
4601 *The Clerk. Mr. Carter votes aye.
4602 *The Chair. Mr. Palmer?
4603 *The Clerk. Mr. Palmer is not recorded.
4604 *The Chair. Mr. --
4605 *Mr. Palmer. Palmer votes aye.
4606 *The Clerk. Mr. Palmer votes aye.
4607 *The Chair. Mr. Goldman?
4608 *Mr. Goldman. Aye.
4609 *The Clerk. Mr. Goldman votes aye.
4610 *The Chair. Mr. Evans?
4611 *Mr. Evans. Aye.
4612 *The Clerk. Mr. Evans votes aye.
4613 *The Chair. Mr. Griffith?
4614 *Mr. Griffith. Aye.
4615 *The Clerk. Mr. Griffith votes aye.
4616 *The Chair. Dr. Joyce?

4617 *Mr. Joyce. Aye.

4618 *The Clerk. Mr. Joyce votes aye.

4619 *The Chair. On the Democrat side is anyone seeking
4620 recognition?

4621 Seeing no one else seeking recognition to answer the
4622 roll call, the clerk will report.

4623 [Pause.]

4624 *The Clerk. Mr. Chairman, on that vote there were 48
4625 ayes and 0 noes.

4626 *The Chair. The ayes have it, and the bill is adopted.
4627 The chair calls up H.R. 9393 and asks the clerk to
4628 report.

4629 *The Clerk. H.R. 9393, a bill to promote price
4630 transparency --

4631 *The Chair. Without objection, the first reading of the
4632 bill is dispensed with, and the bill will be open for
4633 amendment at any point.

4634 So ordered.

4635 [The bill follows:]

4636

4637 *****COMMITTEE INSERT*****

4638

4639 *The Chair. Does anyone seek to be recognized on the
4640 bill?

4641 So the gentleman from Florida is recognized for five
4642 minutes to speak on the bill.

4643 *Mr. Bilirakis. Thank you. I appreciate, Mr. Chairman.
4644 I rise in support of the Combating Illicit Xylazine Act,
4645 legislation that I am proud to co-lead along with my
4646 colleagues, Representatives Panetta, Pfluger, Pappas,
4647 Fitzgerald, and Ross.

4648 Xylazine is a veterinary sedative used to treat large
4649 animals, as you know. Drug traffickers are increasingly
4650 mixing it with fentanyl and other illicit drugs, making an
4651 already dangerous drug supply even more deadly. This
4652 legislation places Xylazine in schedule 3, strengthens law
4653 enforcement's ability to track and combat its diversion into
4654 the illicit market, all while preserving access for
4655 veterinarians, farmers, ranchers, and others who rely on it
4656 for legitimate animal care.

4657 As drug traffickers continue to adapt and evolve,
4658 Congress must ensure that our lives -- again, our laws -- and
4659 enforcement tools remain effective. So I urge my colleagues
4660 to support this particular bill.

4661 And I yield back the balance of my time.

4662 *The Chair. The gentleman yields back. I know there
4663 are several people who want to speak on the bill. We are

4664 going to call up an ANS on the bill. Did anybody want to
4665 speak on the bill or wait until the amendment in the nature
4666 of a substitute?

4667 But I do have one amendment filed to the bill, even
4668 though we are going to pass an ANS. But -- so the gentleman
4669 from Georgia has an amendment filed to the bill.

4670 *Mr. Carter of Georgia. Mr. Chairman, I have an
4671 amendment at the desk.

4672 *The Chair. The clerk will report.

4673 *The Clerk. Amendment to H.R. 9393 offered by Mr.
4674 Carter of --

4675 *The Chair. Without objection, the reading of the
4676 amendment is dispensed with, and the gentleman is recognized
4677 for five minutes to speak on the amendment.

4678 *Mr. Carter of Georgia. Thank you, Mr. Chairman. I am
4679 proud to offer this amendment.

4680 The amendment features two key pieces of our
4681 legislation, the DOC Access Act, that are broadly supported
4682 on a bipartisan basis, aimed to boost transparency in the
4683 vision benefits market and help lower costs for eye and
4684 vision care consumers.

4685 Right now the vision benefits market is largely
4686 dominated by two vertically integrated vision benefit
4687 managers that provide vision insurance coverage to nearly 200
4688 million Americans. These two VPMS (sic) -- and notice I say

4689 VPMS (sic) -- V, as in vision; not P, as in pharmacy, but it
4690 is very, very similar to a PBM -- these two VPMS are not only
4691 the overwhelming provider of vision benefits in America, but
4692 they also manufacture and sell nearly all eyeglass frames and
4693 lenses on the market, nearly all of it made in China. Nearly
4694 all of it made in China.

4695 They also owned thousands of retail optical locations
4696 around the country. They own nearly all optical laboratories
4697 that produce finished prescription eyewear, and they are
4698 aggressively acquiring independent eyecare practices
4699 nationwide at an astonishing pace. These two dominant VPMS
4700 have successfully consolidated the coverage market, and now
4701 they have their sights set on dominating every other aspect
4702 of vision care in America. Did you all catch that? "Sights
4703 set on''? Just -- okay, I just wanted to make sure.

4704 They use this market dominance to keep prices high, to
4705 limit consumer choices, to dictate care, and to --

4706 *The Chair. Will the gentleman suspend?

4707 Let's get the committee to order. So the gentleman
4708 deserves to be heard.

4709 The gentleman is recognized.

4710 *Mr. Carter of Georgia. They use this market dominance
4711 to keep prices high, to limit consumer choices, to dictate
4712 care, and to force doctors and patients to buy the products
4713 they make and use the services they own and operate. Our

4714 amendment aims to confront these abuses, and it is time for
4715 this committee to act.

4716 This amendment is focused on shining the light on and
4717 preventing VPMs from using their market power to steer
4718 patients toward affiliated providers and products. Right now
4719 these VPMs force patients to use optical laboratories that
4720 are owned or under the direct control of their VPM. This
4721 amendment would prevent VPMs from mandating use of one or --
4722 of their subsidiary businesses: their optical lab. Patients
4723 would still have the choice to use the VPM lab if that is
4724 what they wanted, but our amendment would also give them the
4725 freedom to choose another lab that worked best for them based
4726 on cost, quality, and convenience.

4727 Without this fix, patients will continue to face higher
4728 costs, inferior products, and production, and an
4729 unnecessarily long wait times for a finished pair of
4730 prescription eyeglasses.

4731 While we have been working on this issue for years,
4732 states like Georgia, New York, Kentucky, New Jersey,
4733 Illinois, Louisiana, Colorado, Texas, and dozens of others
4734 are passing tough new laws to address a wide range of VBM
4735 abuses. Congress has a responsibility to act, as well,
4736 particularly because millions of Americans receive vision
4737 coverage through federally-regulated plans that fall outside
4738 the reach of many state protections.

4739 Just a few weeks ago the Government Accountability
4740 Office released a report requested by Chairman Guthrie that
4741 highlighted the extraordinary concentration that exists in
4742 the vision benefits marketplace and the challenges it poses
4743 for consumers, independent providers, and all of our
4744 communities. Consumer advocates and patient organizations
4745 are demanding reform. Groups such as Patients Rising and the
4746 National Consumers League have called for greater scrutiny of
4747 VPMs and stronger protections for patients, including those
4748 found in our amendment. Their message is clear: patients
4749 and consumers deserve transparency, competition, choice, and
4750 greater affordability.

4751 We cannot continue to ignore one of the most
4752 concentrated and least transparent segments of the health
4753 care system. By pulling back the curtain on costly,
4754 controlling, and care-limiting VPM practices, we can help
4755 millions of Americans access more affordable vision care,
4756 preserve independent providers, and ensure that patients, not
4757 corporate middlemen, remain at the center of important health
4758 care decisions.

4759 Thank you, Mr. Chairman. I look forward to continuing
4760 to work with you and my colleagues on both sides of this
4761 aisle to advance meaningful VPM reforms, and I yield back.

4762 *The Chair. If the gentleman would yield before you
4763 yield back?

4764 *Mr. Carter of Georgia. I yield.

4765 *The Chair. So we are dedicated to working -- the bill
4766 that you have before us. I know we are waiting for a CBO
4767 score. We are -- technical assistance. And I just -- I
4768 broke my glasses on July the 2nd. I could see my optometrist
4769 within 24 hours. It took me until yesterday to get -- and
4770 the only ones they had. So if you like my glasses or not,
4771 that is what -- that was my option. So it was frustrating to
4772 go a couple of weeks before you could get something fixed.
4773 So I see your point, and we are going to figure out a path
4774 forward.

4775 *Mr. Carter of Georgia. Well --

4776 *The Chair. But we do need the score and we do need
4777 technical assistance, so I appreciate --

4778 *Mr. Carter of Georgia. Understanding that, Mr.
4779 Chairman, I thank you for your cooperation and for your
4780 commitment to make sure that we do address this before the
4781 end of this session, and I will withdraw this amendment.

4782 *The Chair. Thank you. I appreciate the gentleman
4783 withdrawing the amendment.

4784 Without objection, the amendment is withdrawn.

4785 I have an amendment at the desk. It is an amendment in
4786 the nature of a substitute.

4787 Are we going to speak on the -- oh, you want to speak on
4788 his amendment? Oh, okay. Okay, I am sorry. Well, he

4789 withdrew it, but I will go ahead.

4790 So the gentlelady is recognized for five minutes to
4791 speak on the withdrawn amendment.

4792 *Ms. Clarke. I appreciate that.

4793 *The Chair. Okay. We will be deferential.

4794 *Ms. Clarke. I appreciate the gentleman for extending
4795 himself. Mr. Chairman, I move to strike the last word.

4796 *The Chair. The gentlelady is recognized.

4797 *Ms. Clarke. Thank you, Mr. Chairman, Chairman Guthrie
4798 and Ranking Member Pallone, for bringing -- thank you both
4799 for bringing forth H.R. 9393, the Lower Cost, Lower
4800 Transparency Act, to address transparency within health care.
4801 I am pleased to support my colleague and offer this amendment
4802 alongside him, Congressman Buddy Carter, to address an issue
4803 that has affected Americans for far too long.

4804 The health care marketplace has experienced significant
4805 consolidation and vertical integration, reducing transparency
4806 and limiting patient choice particularly for those seeking
4807 vision care. Today the vision insurance market is one of the
4808 most consolidated in the country, with just two national
4809 vision benefit managers, VBMs, covering more than 80 percent
4810 of Americans with vision benefits. This level of market
4811 concentration raises serious concerns about competition,
4812 accountability, and consumer protection.

4813 Americans deserve a vision care system where patients

4814 and families have the information and options they need to
4815 make informed decisions about their care, and that is why
4816 Congressman Buddy Carter and I introduced H.R. 1521, the
4817 Dental and Optometric, DOC, Access Act, bipartisan
4818 legislation that shines a light on opaque business practices,
4819 increases transparency, protects patient choice, and helps
4820 curb anti-competitive behavior that harms consumers.

4821 By advancing this bipartisan legislation, which was
4822 withdrawn, we can help lower the cost and promote
4823 transparency within vision care and ensure that patients, not
4824 profits, come first.

4825 With that, I am going to yield some time to my
4826 colleague, Congresswoman Castor of Florida.

4827 *Ms. Castor. Well, thank you, Rep. Clarke. I wanted to
4828 speak in favor. And I hope, Mr. Chairman, we can see a way
4829 forward on the Carter-Clarke amendment to address vision lab
4830 choice and evergreen contracts. These are two practices that
4831 have contributed to anti-competitive behavior in the vision
4832 insurance marketplace.

4833 For more than a decade patients and providers and
4834 employers have sought meaningful reforms. And as a cosponsor
4835 of the DOC Access Act, I think that the amendment before us
4836 is a narrowly tailored approach that would address
4837 longstanding concerns about consolidation, vertical
4838 integration, and patient choice in the vision benefits

4839 market.

4840 While I understand the amendment has been withdrawn and
4841 won't move forward today, I appreciate the committee's
4842 willingness to keep working on this and to pass necessary
4843 reforms in this space.

4844 Thank you, and I yield back.

4845 *Ms. Clarke. Mr. Chairman, I yield back the balance of
4846 my time.

4847 *The Chair. Thank you. To finish the gentlelady from
4848 Florida's pun, we see a path forward. We will see a path
4849 forward. So thank you.

4850 So are there any further discussions on the amendment
4851 from the gentleman from Georgia?

4852 Seeing none, I have an amendment at the desk, an
4853 amendment in the nature of a substitute.

4854 *The Clerk. Amendment in the nature of a substitute to
4855 H.R. 9393 offered by Mr. Guthrie of Kentucky.

4856 *The Chair. Without objection, the reading of the
4857 amendment is dispensed with.

4858 [The amendment of The Chair follows:]

4859

4860 *****COMMITTEE INSERT*****

4861

4862 *The Chair. And I will recognize myself for five
4863 minutes in support of my amendment.

4864 So I offer my strong support for the amendment to H.R.
4865 9393, the Lower Cost, More Transparency Act of 2026, which
4866 incorporates numerous bipartisan priorities of the members of
4867 this Committee and for the underlying bill, and I urge all of
4868 my colleagues to support it.

4869 H.R. 9393 is the accumulation of many months of work by
4870 this committee to assess health care affordability challenges
4871 and identify opportunities to lower costs for American
4872 families. I was proud to introduce this legislation with my
4873 good friend, Ranking Member Pallone.

4874 In just the last seven months we have held hearings with
4875 the insurance CEOs, members of the drug supply chain,
4876 hospitals, and doctors. We have conducted critical oversight
4877 of waste, fraud, and abuse in the health care system, and we
4878 have assessed opportunities to enhance transparency for
4879 consumers. The ANS which we are considering today takes
4880 lessons from those -- each of those hearings, and creates a
4881 comprehensive health care package that will strengthen health
4882 care price transparency, hold insurers accountable to their
4883 patients, lower drug prices, and expand access to care.

4884 This bill improves price transparency across the health
4885 care system by codifying and building on the Trump
4886 Administration's historic price transparency regulation, and

4887 extends these requirements to lab tests and imaging services,
4888 as well as ambulatory surgical centers. This will give
4889 consumers and employers the tools they need to find the
4890 highest quality of care at the lowest price.

4891 This package will also hold insurers accountable by
4892 requiring insurers to publish their overhead costs and claims
4893 payments and information about how they employ prior
4894 authorization. This information will help consumers better
4895 shop for care and find the best plan for their family.

4896 This bill will lower drug prices by creating -- by
4897 cutting unnecessary red tape that has allowed consumers --
4898 that has slowed consumer access to lower-cost alternatives
4899 for biosimilars and over-the-counter medications.

4900 This bill also expands access to care by ensuring that
4901 behavioral and mental health and substance use disorder
4902 services are available at community health centers and by
4903 helping integrate evidence-based nutrition education and
4904 counseling into primary care delivery and workforce training
4905 at federally-qualified health centers.

4906 Ultimately, this bill delivers on its title and serves
4907 the American people by lowering costs and driving increased
4908 transparency across the health care system. While there is
4909 more work to be done as we continue our efforts to improve
4910 this bill through the legislative process, I am extremely
4911 proud of the bipartisan work that we have done here to make

4912 our health care system work better for patients across the
4913 country. That brings us all together on this committee,
4914 ensuring that our constituents has access to the best care at
4915 the best price.

4916 And with that I strongly urge my colleagues on both
4917 sides of the aisle to support this amendment and the
4918 underlying bill, and I will yield back, and I will recognize
4919 the gentleman from New Jersey for five minutes to speak on
4920 the amendment.

4921 *Mr. Pallone. Thank you, Mr. Chairman. I move to
4922 strike the last word.

4923 *The Chair. The gentleman is authorized to speak on the
4924 amendment.

4925 *Mr. Pallone. The Lower Cost, More Transparency Act
4926 will improve transparency in our health care system, lower
4927 Americans' drug costs, and expand access to mental and
4928 behavioral health care at community health centers, and I am
4929 proud of the work we have done together and the investments
4930 we are making in community health centers.

4931 Despite the fact that the hospital and transparency and
4932 coverage requirements went into effect over five years ago,
4933 some consumers still cannot obtain price information in
4934 advance. Too many patients are forced to wait until after
4935 they receive care and have the medical bill to fully
4936 understand how much they owe. And lack of transparency into

4937 health care prices makes it difficult for consumers to make
4938 informed decisions.

4939 It also makes it challenging for employers to negotiate
4940 more competitive prices. This bill strengthens and expands
4941 access to price information across the health care industry
4942 including hospitals, laboratories, insurance companies,
4943 ambulatory surgical centers, and imaging providers. Greater
4944 transparency will empower both employers and consumers by
4945 helping them compare prices and achieve savings.

4946 I am also pleased that the bill includes a proposal that
4947 will require hospitals to disclose ownership data. I thank
4948 the chairman for working together on this proposal. The bill
4949 will help increase transparency of hospital ownership and
4950 provide a greater insight into hospital consolidation.

4951 Additionally, I am glad the bill includes several
4952 proposals to increase transparency in the Medicare Advantage
4953 program. Representative McClellan's bill will require MA
4954 insurance companies to report data on supplemental benefits,
4955 and will provide important information to regulators and
4956 policy-makers to help us conduct oversight and assess the
4957 program's performance. Several other policies will hold MA
4958 insurance companies accountable and increase transparency of
4959 the prior authorization process in the MA program.

4960 I am concerned about MA plans' misuse of prior
4961 authorization requirements and the negative impacts that

4962 these practices have on patients accessing timely care, but
4963 this bill will ensure our seniors are receiving timely,
4964 medically necessary care without unwarranted barriers.

4965 I am very pleased also that we have included language to
4966 expand access to mental and behavioral health care community
4967 health centers. This bill includes dedicated funding to
4968 expand access to these services. With this investment it is
4969 estimated that community health centers will be able to
4970 expand behavioral health services to about 150,000 more
4971 patients.

4972 And finally, our version, you know, with the ANS,
4973 includes several important policies that will promote drug
4974 competition and lower drug prices for Americans, specifically
4975 the language which codified the FDA's approach to designating
4976 biosimilar drugs as interchangeable, and also allow for FDA
4977 to approve a biosimilar without additional clinical studies
4978 if current scientific evidence is already sufficient. These
4979 policies would reduce development time and cost to more
4980 quickly bring additional options to patients.

4981 The language would also implement important reforms to
4982 preventing gaming of citizen petitions by brand name drug
4983 companies. For years I fought for this policy to prevent
4984 companies from filing such petitions for the primary purpose
4985 of delaying generic drugs from coming to market, and I am
4986 glad that we are including this common-sense proposal here

4987 today, as well.

4988 And finally, the language also establishes a designation
4989 process for FDA to more quickly review applications to safely
4990 bring certain drugs to market for over-the-counter use, which
4991 I hope will improve patient access to safe medications.

4992 So I strongly urge my colleagues to join me in
4993 supporting this bill, as amended.

4994 And thank you again, Mr. Chairman. I yield back.

4995 *The Chair. Thank you. I appreciate that. I know a
4996 lot of members have bills within this bill, and so we are
4997 going to have a lot of discussion. I appreciate that.

4998 I will go to the gentleman from Ohio for five minutes to
4999 speak on the bill -- on the amendment.

5000 *Mr. Latta. Well, thank you very much, Mr. Chairman. I
5001 move to strike the last word in support of the ANS to H.R.
5002 9393, which includes my legislation, the Non-Prescription
5003 Drug Innovation Act that I introduced with our colleague from
5004 Ohio's 1st district.

5005 Over-the-counter, OTC, medicines are one of the most
5006 effective tools we have to improve access to care. They
5007 provide safe, convenient, and lower-cost treatment options
5008 that Americans manage common health conditions with the time
5009 and expense of obtaining a prescription (sic). This
5010 bipartisan piece of legislation will establish an expedited
5011 FDA review pathway for certain OTC drugs that address unmet

5012 health needs and encourage innovation in promising
5013 therapeutic areas where consumers currently have few or no
5014 non-prescription treatment options.

5015 This legislation also builds on the bipartisan reforms
5016 Congress enacted through the most recent reauthorization of
5017 the Over-the-Counter Monograph User Fee Program, OMuFA,
5018 reforms that I was proud to lead. Those reforms strengthened
5019 FDA's review of non-prescription drugs and improved the
5020 agency's engagement with sponsors to support the development
5021 of new OTC products.

5022 The Non-Prescription Drug Innovation Act represents the
5023 next step. It creates a pathway to help bring innovative,
5024 non-prescription therapies to patients more efficiently while
5025 preserving FDA's rigorous standards for safety and
5026 effectiveness. At a time when Americans continue to face
5027 rising health care costs, we should be looking for
5028 opportunities to expand access to safe, effective, and
5029 affordable treatment option. This legislation does exactly
5030 that.

5031 I urge my colleagues to support the ANS and I yield back
5032 the balance of my time.

5033 *The Chair. The gentleman yields back. The gentlelady
5034 from Colorado is recognized for five minutes to speak on the
5035 amendment -- or the bill in the nature of a substitute.

5036 *Ms. DeGette. Thank you so much, Mr. Chairman, and

5037 thank you for bringing this ANS up.

5038 The Lower Cost, More Transparency Act is legislation
5039 that we, frankly, have been working on as a committee to get
5040 signed into for laws (sic).

5041 On the margin, price transparency helps consumers. But
5042 the system-wide transparency which this bill takes a concrete
5043 step towards, will help payers, providers, policy-makers, and
5044 researchers get a better handle on exactly how money flows in
5045 our too-complex health care system, and provides tools for us
5046 to bring down costs. I just have to highlight two major
5047 improvements to this legislation that are contained in the
5048 ANS.

5049 First, it includes my bill with Representative Joyce,
5050 the Medicare Advantage Cost Transparency Act, which will
5051 shine light on pricing practices for seniors on Medicare
5052 Advantage plans. Specifically, it will require MA plans to
5053 report their encounter data, cost sharing, and pricing data,
5054 and, critically, information on their use of in-home health
5055 assessments.

5056 A 2024 inspector general report found that every year
5057 taxpayers fund billions of dollars in overpayments to MA
5058 companies based on unsupported diagnoses from home health
5059 assessments, which rarely result in the seniors receiving
5060 follow-up care. It also found that a fraction of MA plan
5061 sponsors drove 80 percent of those over-payments. This bill

5062 will help reveal any bad actors and the extent of their
5063 practices, as well as other information on pricing to give
5064 Congress a better picture of costs in MA.

5065 And I want to thank my friend, Dr. Joyce, for partnering
5066 with me on this issue.

5067 Second, this ANS incorporates portions of the ownership
5068 transparency amendment I offered in subcommittee. It
5069 requires hospitals and other health care providers to report
5070 information on their ownership structure, mergers,
5071 acquisitions, and consolidation, providing the Federal
5072 Government and consumers vital information because mounting
5073 evidence shows that consolidation and private equity
5074 investments in health care are major drivers of cost in the
5075 system, and in some cases there are correlations with
5076 ownership structures and quality, as well.

5077 Unfortunately, the language does not ensure the ultimate
5078 owners of a given provider entity will be revealed -- only
5079 the immediate parent company, rather than any companies that
5080 own the parent company. I don't understand why it is such a
5081 fight to get that information about the ultimate owners. I
5082 hear people say it is burdensome for hospitals to have to
5083 report on their ultimate parent company rather than their
5084 immediate parent company. But I have got to tell you, I
5085 think that is ridiculous. You are telling me that a hospital
5086 might not know who ultimately owns it?

5087 The only explanation is that some people are fighting
5088 very hard to obscure what is happening in the health care
5089 system. I know you will all be shocked to hear that. If
5090 private equity and other owners are so good for providers and
5091 patients, they should be proud to say so. That they prefer
5092 secrecy speaks volumes.

5093 Thanks to the leadership of Representatives Schakowsky
5094 and Bilirakis on this issue, many of us voted for these
5095 provisions on a bipartisan basis last Congress. I think
5096 there is more we can do now, so I hope to see that the
5097 ownership transparency portions of the bill will be further
5098 strengthened before it passes the House, and I will look
5099 forward to working with you and the chairman of the Health
5100 Subcommittee to make this happen. And moving forward I hope
5101 the bill will give Congress the information we need to curb
5102 monopolistic power and truly lower costs for patients.

5103 For those reasons I urge everybody to support the ANS
5104 and I yield --

5105 *The Chair. Would you yield?

5106 *Ms. DeGette. I would be happy to yield.

5107 *The Chair. You are always good to work with, and you
5108 were working with Fred Upton, the previous chairman of this
5109 committee, and completely changed the way we do health care
5110 in this country by --

5111 *Ms. DeGette. Thank you.

5112 *The Chair. -- the Cures Act, and brought treatments to
5113 the marketplace quicker during our last pandemic. It
5114 wouldn't have happened without your leadership.

5115 *Ms. DeGette. Thank you.

5116 *The Chair. Thank you for that. And I will yield back
5117 to you --

5118 *Ms. DeGette. Let's do some more before this Congress
5119 ends.

5120 [Applause.]

5121 *The Chair. And you have already approached me. There
5122 is more to do in the next few weeks or months together.

5123 *Ms. DeGette. Yes, there sure is.

5124 *The Chair. I appreciate that very much. Thanks for
5125 your hard work. It really is a legacy. Thank you.

5126 I yield back to you and yield back to me, so now I will
5127 recognize the gentleman from -- anybody?

5128 The gentleman from Pennsylvania is recognized for five
5129 minutes to speak on the ANS.

5130 *Mr. Joyce. Thank you, Mr. Chairman. I do wish to
5131 speak in support of this ANS, which, as Representative
5132 DeGette just pointed out, includes H.R. 9392, the Medicare
5133 Advantage Cost Transparency Act.

5134 And thank you, Congresswoman DeGette. Thank you for
5135 partnering on this important bipartisan legislation, and
5136 thank you for the leadership that you have shown this

5137 committee throughout your time here.

5138 This bill represents an important step in the right
5139 direction in improving encounter data submissions made by
5140 Medicare Advantage plans to ensure that they account for the
5141 total allowable cost for items and services and include the
5142 amount of cost sharing imposed on the beneficiary for such
5143 services. This higher level of transparency will help inform
5144 both the public and policy-makers as we further evaluate the
5145 Medicare Advantage programs with more objective data.

5146 Thank you, Chairman Guthrie and Chairman Griffith, for
5147 including this important piece of legislation as part of this
5148 broader transparency package. And I, along with
5149 Representative DeGette, encourage all of my colleagues to
5150 support the ANS and support the underlying bill.

5151 Thank you, Mr. Chairman, and I yield back.

5152 *The Chair. The gentleman yields back. The chair now
5153 recognizes the gentlelady from California for five minutes to
5154 speak on the -- are those votes?

5155 Okay, so votes were just called. And obviously, we are
5156 not going to get through all of this, but let's do a couple
5157 more. And we are not going to have a vote before votes,
5158 before -- so we will reconvene five minutes after the last
5159 vote is called.

5160 *Ms. Matsui. Okay.

5161 *The Chair. And so -- and I think there is going to be

5162 a lot of discussion, so just know that. But -- so we won't
5163 have any -- for your time we won't have any vote for -- after
5164 votes.

5165 All right, the gentlelady from California.

5166 *Ms. Matsui. Thank you very much, Mr. Chairman and
5167 Ranking Member Pallone, for bringing this important
5168 legislation to us. I rise today to speak in support of the
5169 Lower Cost, More Transparency Act.

5170 This bill would expand nutrition, education, mental
5171 health, and substance use treatment services at community
5172 health centers. We know these expansions lead to more people
5173 getting the care they need. I have long championed greater
5174 access to mental health services and clinics within our
5175 community. I led the movement to expand participation in
5176 certified community behavioral health clinics, or CCBACs, a
5177 Medicaid demonstration program to any state that wanted to
5178 participate. We expanded the CCBAC demonstration model from
5179 8 states in 2017 to 31 states today. And along with the
5180 expanded use of Medicaid demonstration models, we now have
5181 CCBAC programs in 46 states. This has been a huge increase
5182 in affordable mental health services directly into
5183 communities that need them the most.

5184 This legislation builds on that work. It continues the
5185 patterns of expanding mental health and substance use
5186 services into community health centers, where millions of

5187 Americans already access their care. Every year over 52
5188 million Americans visit a health center, and 14 percent of
5189 patients receive their primary care at these clinics. For
5190 many patients, especially those in rural and underserved
5191 communities, health centers are the only place they can
5192 access any care. This bill will help ensure that these
5193 patients can access the full scope of health care services
5194 directly in their communities.

5195 Additionally, this bill provides funding for community
5196 health centers to deliver nutrition education and chronic
5197 disease prevention workforce training for their clinics.
5198 Nutrition is a crucial piece of health care that is often
5199 forgotten inside the walls of a clinic. For diseases like
5200 diabetes and heart disease, two of the leading causes of
5201 death in the United States, adhering to a healthy diet can
5202 help control or, in some cases, reverse disease progression.
5203 Proper diet and exercise can also help prevent the
5204 development of some chronic diseases, resulting in longer and
5205 healthier lives.

5206 If we want health centers to provide high-level
5207 nutrition education and training for the workforce, we must
5208 provide the funding for them to do so. In the wake of the
5209 devastating cuts from H.R. 1, health centers are already
5210 stretched to continue to provide standard health care
5211 services. Knowing that, I am happy to see that this bill

5212 includes \$125 million in funding per year to implement these
5213 new services and to train the health center workforce.

5214 Additionally, this bill authorizes \$250 million per year
5215 for expanding mental health and substance use treatment. If
5216 we want health centers to provide high-level care, we must
5217 ensure they have the proper funding to do so. I commend my
5218 colleagues for bringing forward this legislation and for
5219 continued push for increased access to care for all
5220 Americans.

5221 I strongly support this legislation and the underlying
5222 ANS, and will work with my colleagues to ensure that adequate
5223 funding is appropriated yearly to continue to support
5224 community health centers, mental health and substance use
5225 services, and nutrition education for all communities.

5226 And with that I yield the balance of my time.

5227 *The Chair. The gentlelady yields back, and we will do
5228 one more speaker so everybody didn't have to get up and leave
5229 in the middle of a speaker. So we will have one more speaker
5230 and then we will recess for votes.

5231 So Mr. Pfluger is next.

5232 *Mr. Pfluger. Thank you, Mr. Chairman, and I will make
5233 it quick, but this is exactly the kind of common-sense,
5234 bipartisan work the committee should be doing. I am so very
5235 proud to join in on this. I have two bills to talk about.

5236 The first is the Premium Transparency Act that I am

5237 leading with representative Moran. And Americans deserve to
5238 know where their health insurance dollars are actually going.
5239 Insurers are required to spend at least \$0.80 to \$0.85 of
5240 every premium dollar on patient care, but right now that
5241 information is buried in regulatory filings that almost
5242 nobody ever sees. This bill brings it out into the open in
5243 plain language that any patient, any family, any person, any
5244 employer can understand.

5245 And what Americans -- when Americans have that
5246 information in hand, they can start demanding real value for
5247 their health care dollar, and that is where the market starts
5248 working for patients instead of against them. President
5249 Trump's Great American Healthcare Plan puts patients first,
5250 and this bill helps codify that promise.

5251 Transparency is only half the equation, however. And
5252 the other is making sure that bureaucratic red tape does not
5253 stand in the way of Americans accessing lower-cost options.
5254 That is what the Biosimilar Red Tape Elimination Act does for
5255 prescription drugs, legislation that I am proud to lead
5256 alongside my colleague, Representative Greg Landsman.

5257 Expensive biologic medications make up just 5 percent of
5258 prescriptions in the U.S., but 51 percent of drug spending.
5259 Biosimilars are the safe, effective, lower-cost alternatives.
5260 And since entering the market in 2015, they have already
5261 saved patients more than \$56 billion. But Federal law has

5262 not caught up to the science, and current law maintains an
5263 outdated statutory distinction between biosimilar and
5264 interchangeable similar, products that is not based on any
5265 clinical or scientific difference. That unnecessary
5266 distinction is exactly what keeps Americans from accessing a
5267 less expensive version of their drugs, medicine.

5268 The FDA in both the Biden and the Trump Administrations
5269 has repeatedly affirmed that there is no meaningful
5270 difference in safety or efficacy between the two categories,
5271 with the Trump Administration making strides to accelerate
5272 biosimilar development. However, they need Congress to
5273 finish the job. The Biosimilar Red Tape Elimination Act
5274 offers a straightforward, science-based fix. The bill would
5275 deem all FDA-approved biosimilars interchangeable with their
5276 reference products. By aligning Federal law with the FDA's
5277 scientific recommendation, the legislation will reduce
5278 regulatory red tape, strengthen biosimilar competition, and
5279 deliver lower prices.

5280 Mr. Chairman, thanks for having this markup, and I yield
5281 back.

5282 *The Chair. The gentleman yields back. And so I will
5283 come back. As soon as the last votes call I will come
5284 straight back, and we can get more discussion started.

5285 A Democrat will be up next, and we will recess until
5286 call of the chair. Hopefully, five minutes after the last

5287 vote.

5288 [Recess.]

5289 *The Chair. All right, the committee will come to
5290 order. Thanks, everybody, for prompt returning.

5291 We were speaking on the Lower Cost, More Transparency
5292 bill and on the amendment in the nature of a substitute, and
5293 it was time for the other side. The gentleman from -- the
5294 gentlelady from Massachusetts, or gentleman -- I can start
5295 with the gentleman from Massachusetts, if you like.

5296 The gentleman from Massachusetts is recognized for five
5297 minutes to speak on the bill.

5298 *Voice. On the ANS.

5299 *The Chair. To speak on the amendment in the nature of
5300 a substitute.

5301 *Mr. Auchincloss. Yes, thank you, Chairman. I want to
5302 talk about the two biosimilar bills that we have in this ANS,
5303 the Biosimilar Red Tape Elimination Act and the Expedited
5304 Access to Biosimilars Act.

5305 These are just two big bipartisan wins for innovation
5306 and affordability. They are meeting the moment when it comes
5307 to just the really staggering amount of invoice spend in this
5308 country on biologics that could have a competitor on the
5309 market but do not, something like \$100 billion. And both of
5310 them are pro-competitive ways of getting more biosimilars to
5311 market faster, and it really underscores to me that

5312 competition is always the best way to lower drug prices and
5313 to reduce costs in the health care system. And as a
5314 committee, we should be working on more bipartisan drug
5315 pricing proposals that expedite competition, strengthen
5316 competition like these two biosimilar bills.

5317 And there is two or three other, I think, complementary
5318 measures that I would hope this committee would consider, as
5319 well, that would induce more competition in the biosimilars
5320 market. One of them would be the sequel to the PBM reform
5321 that we did at the beginning of this term, which is one
5322 fiduciary status for pharmacy benefit managers under ERISA;
5323 and two is really cracking down on PBMs' use of white
5324 labeling and rebates to keep biosimilars off market. We are
5325 seeing really anti-competitive practices that are, one, a
5326 violation of a fiduciary status by a PBM to their employer
5327 when they are keeping that employer paying more for biologics
5328 when there could be a biosimilar on the market but they are
5329 using rebates to keep that biosim off the market.

5330 And so those two bills are complementary. Those two
5331 policies are complementary. One, tell the PBMs you have got
5332 to do what is in the best interest of your plan sponsor and
5333 employees; and two, you can't use rebates to try to keep
5334 competitors off the market. So I would encourage the
5335 committee to be considering those two proposals for
5336 biosimilars, as well.

5337 And I think we should also be looking at whether there
5338 are improvements we can make within part B so that, as
5339 biologics come up for consideration for price negotiation
5340 under the Medicare Drug Price Negotiation program, that
5341 potential competition from biosimilars is allowed to flower
5342 before that price negotiation sets in because, again, the
5343 best way to lower prices and deliver the highest quality
5344 product to people is competition, and we want to allow that
5345 biosims market to be able to compete, including with
5346 biologics that are coming up on their price negotiation
5347 period.

5348 I think that is it for me, Chair, I will yield back.

5349 *The Chair. The gentleman yields back. Is there
5350 further discussion on the bill?

5351 The gentleman from New York is recognized for five
5352 minutes to speak on the amendment.

5353 *Mr. Langworthy. Mr. Chairman, I move to strike the
5354 last word.

5355 *The Chair. The gentleman is recognized to speak on the
5356 amendment.

5357 *Mr. Langworthy. I want to thank Chairman Guthrie for
5358 including my bill, H.R. 9661, the Expedited Access to
5359 Biosimilars Act, in today's amendment in the nature of a
5360 substitute.

5361 I would also like to thank my colleague, Representative

5362 Kim Schrier, for partnering with me on this common-sense
5363 bipartisan legislation.

5364 No matter where we go in our districts, we hear the same
5365 thing: prescription drugs simply cost too much. That is
5366 especially true for patients who rely on biologic medicines
5367 to treat cancer and other serious chronic illnesses. These
5368 medicines have changed countless lives, but they are also
5369 some of the most expensive prescriptions on the market, and
5370 that is where biosimilars can make a real difference. They
5371 offer patients a lower-cost alternative to many of those
5372 treatments. And as more patients rely on these medicines,
5373 making sure those low-cost options reach the market without
5374 unnecessary delays becomes even more important.

5375 Today biosimilars typically cost 15 to 35 percent less
5376 than comparable brand-name biologics. In one recent study
5377 patients using biosimilars paid about \$200 less out of
5378 pocket, on average, than patients using the reference
5379 biologic. That is real money for families already juggling
5380 doctor's appointments, treatments, and everything else that
5381 comes with a serious illness.

5382 Now, unfortunately, patients don't always get access to
5383 those savings as quickly as they should because regulatory
5384 delays can slow that process. Every unnecessary delay is
5385 another day patients are forced to wait for more affordable
5386 treatment options. That is exactly what this legislation is

5387 designed to fix.

5388 The Expedited Access to Biosimilars Act, it cuts
5389 regulatory red tape while preserving the FDA's authority to
5390 require additional studies whenever the science actually
5391 supports doing so. If additional studies are necessary, the
5392 FDA can require them; but if they aren't, patients shouldn't
5393 have to wait longer or pay more because of unnecessary
5394 bureaucracy. This is a common-sense reform that helps get
5395 safe, lower-cost medicines to patients faster without cutting
5396 corners on the science. It lowers prescription drug costs,
5397 it expands patient choice, and it ensures red tape doesn't
5398 stand in the way of treatment.

5399 I urge my colleagues to support the amendment in the
5400 nature of a substitute.

5401 And I yield back, Mr. Chairman.

5402 *The Chair. The gentleman yields back. Is there
5403 further discussion on the amendment in the -- the gentlelady
5404 from Washington is recognized for five minutes to speak on
5405 the bill.

5406 *Ms. Schrier. Thank you, Mr. Chairman. I also move to
5407 strike the last word.

5408 *The Chair. The gentlelady is recognized for five
5409 minutes.

5410 *Ms. Schrier. Thank you. I wanted to just take a
5411 moment to talk about two of the excellent bills in this

5412 package, the Prior Authorization Accountability Act and the
5413 Expedited Access to Biosimilars Act.

5414 I hear from constituents all the time about how fed up
5415 they are with their health insurance company. They pay a lot
5416 of money for peace of mind and for real coverage, and then
5417 their insurance company delays or denies care due to really
5418 abusive prior authorization tactics. That is why I am a
5419 proud cosponsor of the Prior Authorization Accountability Act
5420 which is included in this ANS.

5421 This bill requires commercial health plans to make
5422 information regarding their prior authorization requirements
5423 public, like what services are being pre-authed and how
5424 frequently; how frequently they are denying care; how many of
5425 those denials are appealed; and then how many of those
5426 denials are ultimately approved. Patients deserve this
5427 information so they know what they are signing themselves up
5428 for, and lawmakers need this insight so that we can prevent
5429 this abuse in the system.

5430 For example, if plans have high prior authorization
5431 approval rates, are they necessary in the first place? Or is
5432 the insurance plan just creating more red tape for patients
5433 to jump through? Lots of studies. If lots of studies or
5434 procedures are denied and then they are ultimately approved
5435 after appeals, then why weren't they approved in the first
5436 place? These are really important questions that have to be

5437 answered so that patients can get better, more timely care
5438 and so we can cut red tape, bring down costs, and help our
5439 health care system really take care of people's health. And
5440 it is the first step toward more substantive prior
5441 authorization reform that benefits patients, not large
5442 insurance companies trying to pad their own pockets.

5443 I encourage my colleagues to vote yes on the underlying
5444 ANS, and I want to talk about one other bill about the
5445 expedited biosimilars.

5446 With regard to biosimilars, two things can be true:
5447 innovation is critical to the American economy, and every
5448 American should be able to afford their medications. And one
5449 way that our current system balances these two ideals is with
5450 generics and with biosimilars, which are drugs that come to
5451 the market after patents have expired and are essentially
5452 identical to their name-brand counterparts. Generics and
5453 biosimilars increase competition in the market, providing
5454 more options and lowering costs for patients. That is why
5455 last week I introduced with Mr. Langworthy the Expedited
5456 Access to Biosimilars Act which makes it easier for these
5457 low-cost drugs to come to market, and I am really grateful
5458 for that bipartisanship and partnership.

5459 For patients with chronic conditions like autoimmune
5460 diseases or diabetes or cancer, there are biosimilars on the
5461 market that cost significantly less than their name brand

5462 biologic counterparts. My bill streamlines the approval
5463 process for biosimilars by eliminating requirements for
5464 unnecessary and duplicative clinical studies while still
5465 maintaining FDA's authority to require additional studies if
5466 and when they are really needed. This is an important step
5467 toward lowering costs for patients, and I encourage all of my
5468 colleagues to vote yes on the underlying ANS.

5469 Thank you, and I yield back.

5470 *The Chair. The gentlelady yields back. Is there any
5471 discussion on -- further discussion on the amendment in the
5472 nature of a substitute on the Republican side?

5473 Seeing none, the gentlelady from Massachusetts is
5474 recognized for five minutes to speak on the amendment.

5475 *Mrs. Trahan. I move to strike the last word.

5476 *The Chair. The gentlelady is recognized to speak on
5477 the amendment.

5478 *Mrs. Trahan. Thank you, Chairman.

5479 I am glad that this legislation is finally moving
5480 forward, and I am especially pleased to see that the
5481 ownership transparency bill was included in the ANS. This is
5482 a common-sense, long-overdue reform, and I am grateful to my
5483 colleagues on both sides of the aisle for getting us here.

5484 As I have raised in this committee time after time over
5485 the years, it is long past due that we shine a light on
5486 private equity's role in our health care system. Steward

5487 Health Care's collapse should have been the warning bell.
5488 After buying up distressed community hospitals in
5489 Massachusetts, Steward's opaque ownership structure let its
5490 owners get away with shocking financial management and
5491 patient neglect, all while they turned a massive profit.
5492 Communities in the state that I represent are still reeling.
5493 Two hospitals closed outright, a third was forced to shutter
5494 essential services. And one of those closures, Nashoba
5495 Valley Medical Center, left a gap in emergency care that we
5496 are still working to fill.

5497 And I am not the only member of this committee with
5498 stories like this. Steward ravaged hospitals in Texas.
5499 Prospect ran hospitals into the ground in Rhode Island and
5500 Connecticut. Pipeline did the same in Chicago. Nursing
5501 homes across the country have been pillaged, too. These
5502 repeated disasters have left patients, families, and entire
5503 communities devastated in their wake.

5504 Meanwhile, private equity keeps gobbling up distressed
5505 providers. In fact, over the past decade PE firms have spent
5506 more than \$1 trillion buying up health care businesses. And
5507 in 2025 they were involved in nearly half of the largest
5508 health care bankruptcies in the country. Yet up until now
5509 nothing had been done here in Congress to stop it from
5510 happening again. But today we are finally stepping up and
5511 increasing transparency into who actually owns our health

5512 care facilities.

5513 This provision isn't new. This committee already voted
5514 for this exact language last Congress as part of our
5515 bipartisan negotiated health transparency package. And this
5516 time I hope we can all commit to getting it done. We know
5517 what the evidence shows, we know what happened to communities
5518 like mine, and we know what is bound to happen to other
5519 communities if we fail to get this done. So let's get this
5520 common-sense policy across the finish line.

5521 I want to thank you, and I yield back the balance of my
5522 time. Thanks.

5523 *The Chair. The gentlelady yields back. Is there
5524 further discussion on the bill?

5525 Seeing no discussion on the bill on our -- on the
5526 Republican side, so the gentleman from Florida is recognized
5527 for five minutes to speak on the amendment in the nature of a
5528 substitute.

5529 *Mr. Soto. Thank you, Chairman. We need more price
5530 transparency in health care for hospitals, clinics, surgical
5531 centers, labs, and imaging. Patients deserve no less.

5532 We have great hospitals, great health care institutions
5533 in central Florida, yet I have still heard this story
5534 countless times: patients going in for emergency procedures
5535 or other types of medical procedures and have no idea what it
5536 will cost. Some will be covered by health insurance, and we

5537 passed the No Surprises law just a few years ago to make sure
5538 that those with health insurance don't get caught in the
5539 middle of disputes between health insurance companies and
5540 health providers. And we need more work on that new law.
5541 And some of the costs will be out-of-pocket expenses. This
5542 is where patients need to know exactly what they are getting
5543 into and know what they are going to be paying for.

5544 But also, there is -- it is especially acute with those
5545 without insurance, because they will be paying all of this
5546 out of pocket. And it is an important time to remind
5547 ourselves that 2 million Floridians have lost their health
5548 insurance over this past year because of ACA and Medicaid
5549 cuts, including 150,000 in our district. And so price
5550 transparency is very important. This committee must also
5551 address this health care crisis to lower health care costs
5552 for Floridians and folks across the nation.

5553 With that I yield back.

5554 *The Chair. The gentleman yields back. Are there any
5555 speakers on the amendment in the nature of a substitute on
5556 the Republican side?

5557 Seeing none, the -- are there any further speakers on
5558 the Democratic side?

5559 The gentlelady from Michigan is recognized for five
5560 minutes to speak on the amendment.

5561 *Mrs. Dingell. Thank you, Mr. Chair. I move to strike

5562 the last word.

5563 *The Chair. The gentlelady is recognized.

5564 *Mrs. Dingell. Thank you, Mr. Chair.

5565 We continue to hear from our constituents in communities
5566 across the country that the price of health care is just too
5567 high, putting important and often lifesaving care out of
5568 reach. Patients are already navigating a complicated health
5569 care system and paying ridiculously expensive bills that
5570 often don't reflect the level of the care they receive.
5571 Total health care spending and insurance premiums continue to
5572 rise, putting families in the impossible decision to either
5573 get the care they need or put food on the table.

5574 As we continue working to lower costs, it is critical
5575 that price transparency remain at the forefront. Price
5576 transparency empowers patients to make informed decisions.
5577 When patients can see prices before receiving care, they are
5578 better equipped to compare options, plan for expenses, and
5579 avoid unexpected medical bills. Patients deserve the same
5580 access to pricing information that they expect in nearly
5581 every sector of the economy. No patient should avoid going
5582 to the doctor or seeking medical care because they fear being
5583 stuck with an outrageous bill they never saw coming. They
5584 deserve to know the cost of care before they receive it, not
5585 weeks later when the bill arrives in the mail.

5586 Transparency does something even more important. It

5587 promotes competition. When hospitals, insurance, pharmacy
5588 benefit managers, and other health care entities are required
5589 to disclose prices, the market works. It works effectively
5590 to drive down costs and improve the value for patients. But
5591 transparency, as my other colleagues have discussed, alone is
5592 not enough if the marketplace itself is becoming less
5593 competitive.

5594 We are seeing major corporations buy up different parts
5595 of the health care supply chain such as insurers acquiring
5596 physician practices, pharmacy benefit managers owning the
5597 pharmacies, and large systems consolidating hospitals and
5598 providers. This growing vertical integration allows
5599 companies to consolidate power, game the system, inflate
5600 costs, and too often prioritize profits over patients. It is
5601 harming patients, taxpayers, and independent doctors and
5602 pharmacists who can't compete with conglomerates. So if we
5603 truly want transparency to work, we must also ensure there is
5604 meaningful competition in the health care marketplace.

5605 In this ANS we are also taking an important step towards
5606 addressing the growing concern surrounding the use of prior
5607 authorization requirements in Medicare Advantage plans by
5608 adding the Improving Seniors' Timely Access to Care Act. Too
5609 often these bureaucratic requirements create unnecessary
5610 delays, administrative burdens, and, most importantly,
5611 barriers to treatment for seniors who need timely access to

5612 important medical care.

5613 More than 33 million Americans are enrolled in Medicare
5614 Advantage plans, including more than 650,000 seniors in
5615 Michigan. The Improving Seniors' Timely Access to Care Act
5616 would modernize and streamline the prior authorization system
5617 by requiring Medicare Advantage plans to establish an
5618 electronic prior authorization process. We are increasing
5619 transparency by requiring Medicare Advantage plans to report
5620 information about their use of prior authorizations,
5621 including the rate of approvals or, more importantly,
5622 denials.

5623 We will also be taking another important step, changing
5624 that -- by ensuring community health centers are equipped to
5625 provide behavioral health, mental health, and substance use
5626 disorder services as part of the comprehensive care by adding
5627 the Expanding Community Access to Health Services Act in this
5628 package. For many individuals community health centers are
5629 the only places that they can receive affordable primary care
5630 close to home. But too often mental health care and
5631 substance use disorder treatment remain difficult to access,
5632 fragment (sic), or simply unavailable.

5633 Recent studies found that the need for behavioral health
5634 center care has increased in recent years while providers
5635 continue to face staffing shortages and burnout. At a time
5636 when communities are grappling with rising mental health

5637 needs, substance abuse challenges, and barriers to care, we
5638 need to be strengthening these community health centers that
5639 patients already trust and rely on.

5640 I urge my colleagues to support the policies that expand
5641 health care price transparency, expand access to care,
5642 strengthen competition, and make health care more affordable
5643 for Americans.

5644 Thank you, Mr. Chairman, and I yield back.

5645 *The Chair. The gentlelady yields back. Are there any
5646 speakers on the amendment on the Republican side?

5647 Seeing none, on the Democrat side?

5648 The gentleman from Ohio is recognized for five minutes
5649 to speak on the amendment.

5650 *Mr. Landsman. Thank you, Mr. Chair, and I want to
5651 thank you and the ranking member, everyone that -- you put a
5652 ton of work into this bill, the Lower Cost, More Transparency
5653 Act.

5654 I want to lift up three aspects of the bill and, again,
5655 thank you for including these. One is the Biosimilar Red
5656 Tape Elimination Act that would simplify the FDA's approval
5657 process and provide lifesaving medications at a lower cost
5658 for patients. The second is language that requires the FDA
5659 to take steps to speed up the process to bring over-the-
5660 counter drugs to market. And then finally, we have language
5661 in this bill that will require executives of health insurance

5662 plans, hospitals, laboratories, imaging services, and
5663 ambulatory surgical centers to attest that all of the pricing
5664 information they publish is complete and accurate.

5665 We have pushed for transparency before, and sometimes
5666 these providers will provide that transparency in a really
5667 complicated, convoluted way. It is Excel spreadsheets. It
5668 doesn't really work for patients. And so this would require
5669 the CEOs of these providers to be accountable for what they
5670 publish. Even when price data, as I mentioned, is available,
5671 it is often buried in thousands and thousands of pages of
5672 Excel sheets that are missing key details, impossible for
5673 patients to navigate.

5674 We must hold health care executives accountable to the
5675 price transparency information that they publish, and our
5676 amendment which is now in the bill ensures that the burden of
5677 transparency is on the executives of these organizations.
5678 The accountability for health care prices belongs at the top.
5679 This will engage -- ensure health care entities provide
5680 clear, reliable information that patients can actually use to
5681 make informed decisions.

5682 Thank you for your work on this, for including this
5683 important language, and I yield back.

5684 *The Chair. The gentleman yields back. Are there
5685 further speakers on the bill on the Republican side?

5686 Seeing none, any -- the gentlelady from Virginia is

5687 recognized for five minutes to speak on the amendment.

5688 *Ms. McClellan. Thank you, Mr. Chairman, and I want to
5689 thank you and Ranking Member Pallone for your work on this
5690 important bill, the Lower Cost, More Transparency Act, and
5691 thank you for including my bill to increase data transparency
5692 for supplemental benefits under Medicare Advantage.

5693 Every fall millions of seniors sit at their kitchen
5694 table and flip through a stack of Medicare Advantage
5695 brochures, each one promising different supplemental
5696 benefits. In Virginia alone, seniors can choose from 143
5697 Medicare Advantage plans. These plans are sold with promises
5698 of benefits ranging from dental, vision, and hearing to even
5699 gym membership and grocery cards. But we can't tell our
5700 seniors how much of that promise has actually been delivered
5701 to them, and at what cost.

5702 In 2025, MedPAC found that Medicare paid MA plans nearly
5703 \$86 billion in rebates to fund these supplemental benefits,
5704 yet the agency had no reliable data on how many seniors
5705 actually used them or their real value. Seniors are making
5706 enrollment decisions based on these supplemental benefits
5707 with no certainty whether the plan that looks best on paper
5708 will actually deliver what they need when they need it the
5709 most.

5710 At the same time, Medicare Advantage beneficiaries, who
5711 now make up more than half of all Medicare beneficiaries, are

5712 navigating rising costs and a mountain of prior
5713 authorizations, putting prescriptions and treatments out of
5714 reach. Seniors need adequate information about benefits, not
5715 more obstacles to receiving the care they need. And my bill,
5716 which is now included in this one, would require MA plans to
5717 disclose exactly which supplemental benefits are offered, how
5718 seniors are utilizing them, and how much they cost.

5719 With greater transparency around Medicare Advantage
5720 supplemental benefits, seniors will be better equipped to
5721 make medical decisions amid the ongoing affordability crisis.
5722 If Medicare Advantage is going to remain the choice for more
5723 than half of America's seniors, Congress and CMS need real
5724 data to ensure that the program delivers on its promises.

5725 I am also happy to see the committee move bipartisan
5726 legislation, the H.R. 3514, the Improving Seniors' Timely
5727 Access to Care Act, through this ANS.

5728 Prior authorization, which requires health plans to
5729 approve a service before the provider can even deliver it,
5730 poses a significant barrier to timely care, particularly to
5731 women of all ages. In my district I hear from young women
5732 who wait weeks for cervical cancer screenings to be approved,
5733 mothers who are denied hypertension medication mid-pregnancy,
5734 and older women who were denied osteoporosis treatment until
5735 after a preventable fracture. I hear the same frustration
5736 from providers and hospitals who watch a 15-minute prior

5737 authorization request balloon into hours of paperwork, phone
5738 calls, and appeals.

5739 Medicare Advantage, a type of Medicare plan that
5740 contracts with the private insurers to deliver care, is
5741 responsible for an overwhelming majority of prior
5742 authorization requests, with nearly 53 million in 2024
5743 compared to just 600,000 in traditional Medicare. The
5744 Improving Seniors' Timely Access to Care portion of this bill
5745 will require these plans to adopt standardized electronic
5746 prior authorization systems to expedite the processing of
5747 these requests so that providers can focus where they need
5748 to: on patients, not paperwork.

5749 And while the bill modernizes the prior authorization
5750 process for Medicare Advantage plans specifically, this is
5751 only the start because women deserve the same efficiency no
5752 matter where they get their health care coverage and no
5753 matter how old they are. So I am proud to cosponsor that
5754 portion of the bill, as well, and I look forward to working
5755 with the committee on getting the full bill through the
5756 floor.

5757 And with that I yield back.

5758 *The Chair. The gentlelady yields back. Is there
5759 further discussion on the amendment?

5760 Seeing no discussion, are there any amendments to the
5761 amendment?

5762 Are there any amendments to the amendment?

5763 Seeing none, no amendments to the amendment?

5764 *Mr. James. Mr. Chairman, I have an amendment at the
5765 desk.

5766 *The Chair. The gentleman is recognized. The clerk
5767 will report the amendment.

5768 *The Clerk. Amendment to the amendment in the nature of
5769 a substitute to H.R. 9393 offered by Mr. James --

5770 *The Chair. Without objection, the reading of the
5771 amendment is dispensed with.

5772 [The amendment of Mr. James follows:]

5773

5774 *****COMMITTEE INSERT*****

5775

5776 *The Chair. And the gentleman from Michigan is
5777 recognized for five minutes in support of the amendment.

5778 *Mr. James. Thank you, Mr. Chairman. I really
5779 appreciate your efforts here, and your leadership, but still
5780 at this point this bill is missing one of the most important
5781 parts, the part where patients get to see in advance how much
5782 they will get to pay before choosing where to get their
5783 medical care.

5784 Patients Deserve Price Tags will require hospitals to
5785 make their prices easy to find, easy to understand. This
5786 simple change will save patients money by doing what people
5787 already do in every other aspect of their lives: compare
5788 prices and choose the best options for themselves and their
5789 families. A simple explanation of what patients are being
5790 charged: this idea isn't radical, it is not controversial.
5791 No one in this committee has argued against this bill on its
5792 merits.

5793 Patients Deserve Price Tags passed this committee under
5794 suspension of the rules last term, and the ranking member
5795 supported the legislation. It passed the House, full House,
5796 by a vote of 320 to 71. There is an identical version in the
5797 Senate that already has 11 Republicans and 13 Democrat
5798 cosponsors. The White House supports it, HHS supports it,
5799 Secretary Kennedy supported it -- which might actually be a
5800 problem for some of my colleagues.

5801 But by the way, this also helps us stop fraud, waste,
5802 and abuse by increasing transparency and giving control back
5803 to the consumer. Just today I learned that Patients Deserve
5804 Price Tags got a non-partisan CBO score of 122 billion and up
5805 to possibly 270 billion over 10 years. This eclipses the
5806 savings covered under reconciliation, but instead in a
5807 bipartisan way, in a bipartisan vehicle while increasing
5808 choice, while increasing affordability for Americans. This
5809 is why we need to do more.

5810 Hospitals have hidden their prices for far too long and
5811 made billions, billions off of sick Americans, taking
5812 advantage of people who can't comparison shop because it is
5813 too difficult. Hospitals are operating as a confusopoly,
5814 where prices are intentionally hard to find. As a result,
5815 patients can pay hundreds of thousands of dollars more for
5816 the exact same services and pay -- and get the same quality
5817 of care, if not worse, with the exact same billing codes,
5818 depending on where they go.

5819 Our choice is simple, Mr. Chairman: strengthen this
5820 bill to help patients save money or protect a system that is
5821 intentionally confusing and hard to navigate. Protect
5822 patients or protect hospital profits. The American people
5823 want and expect Congress to do more to lower health care
5824 costs, and increase affordability, and cut fraud, waste, and
5825 abuse. Patients Deserve Price Tags will do all three. It

5826 will lower health care costs by requiring hospitals to
5827 clearly label prices so patients can make informed decisions
5828 about where they spend their money and how they get treated,
5829 which is why I am excited to continue my work with you and
5830 your team, Mr. Chairman, to include key protections to
5831 strengthen the final bill.

5832 The chairman has given me his word as a fellow West
5833 Point graduate and as a good friend that we will continue to
5834 strengthen this bill, and I am excited to continue our work
5835 because this is popular, it is bipartisan, it is bicameral,
5836 and it is the right thing to do. I urge the rest of the
5837 committee to support, and I will be withdrawing my amendment
5838 and working to include the strength in the final underlying
5839 bill, Mr. Chairman.

5840 *The Chair. All right, the gentleman withdraws his
5841 amendment?

5842 *Mr. James. I withdraw my amendment, and I cede the
5843 rest of my time, sir.

5844 *The Chair. Without objection, the amendment is
5845 withdrawn.

5846 Are there further amendments to the amendment in the
5847 nature of a substitute?

5848 Seeing -- the question before the Committee is adopting
5849 the amendment in the nature of a substitute.

5850 All in favor, say aye.

5851 All opposed, no.

5852 Are there any further amendments?

5853 Seeing none, the question now occurs on adopting H.R.

5854 9393, as amended. A roll call vote has been requested -- and

5855 I really appreciate everybody's work, this means a lot today

5856 so thank you very much -- and the clerk will call the roll.

5857 *The Clerk. Mr. Latta?

5858 *Mr. Latta. Aye.

5859 *The Clerk. Mr. Latta votes aye.

5860 Mr. Griffith?

5861 *Mr. Griffith. Aye.

5862 *The Clerk. Mr. Griffith votes aye.

5863 Mr. Bilirakis?

5864 *Mr. Bilirakis. Aye.

5865 *The Clerk. Mr. Bilirakis votes aye.

5866 Mr. Hudson?

5867 *Mr. Hudson. Aye.

5868 *The Clerk. Mr. Hudson votes aye.

5869 Mr. Carter of Georgia?

5870 *Mr. Carter of Georgia. Aye.

5871 *The Clerk. Mr. Carter of Georgia votes aye.

5872 Mr. Palmer?

5873 *Mr. Palmer. Aye.

5874 *The Clerk. Mr. Palmer votes aye.

5875 Mr. Dunn?

5876 [No response.]
5877 *The Clerk. Mr. Crenshaw?
5878 [No response.]
5879 *The Clerk. Mr. Joyce?
5880 *Mr. Joyce. Aye.
5881 *The Clerk. Mr. Joyce votes aye.
5882 Mr. Weber?
5883 *Mr. Weber. Aye.
5884 *The Clerk. Mr. Weber votes aye.
5885 Mr. Allen?
5886 *Mr. Allen. Aye.
5887 *The Clerk. Mr. Allen votes aye.
5888 Mr. Balderson?
5889 *Mr. Balderson. Aye.
5890 *The Clerk. Mr. Balderson votes aye.
5891 Mr. Fulcher?
5892 *Mr. Fulcher. Fulcher is aye.
5893 *The Clerk. Mr. Fulcher votes aye.
5894 Mr. Pfluger?
5895 [No response.]
5896 *The Clerk. Mrs. Harshbarger?
5897 *Mrs. Harshbarger. Aye.
5898 *The Clerk. Mrs. Harshbarger votes aye.
5899 Mrs. Miller-Meeks?
5900 *Mrs. Miller-Meeks. Yes.

5901 *The Clerk. Mrs. Miller-Meeks votes aye.
5902 Mrs. Cammack?
5903 [No response.]
5904 *The Clerk. Mr. Obernolte?
5905 [No response.]
5906 *The Clerk. Mr. James?
5907 *Mr. James. Aye.
5908 *The Clerk. Mr. James votes aye.
5909 Mr. Bentz?
5910 *Mr. Bentz. Aye.
5911 *The Clerk. Mr. Bentz votes aye.
5912 Mrs. Houchin?
5913 *Mrs. Houchin. Aye.
5914 *The Clerk. Mrs. Houchin votes aye.
5915 Mr. Fry?
5916 [No response.]
5917 *The Clerk. Ms. Lee?
5918 *Ms. Lee. Aye.
5919 *The Clerk. Ms. Lee votes aye.
5920 Mr. Langworthy?
5921 *Mr. Langworthy. Aye.
5922 *The Clerk. Mr. Langworthy votes aye.
5923 Mr. Kean?
5924 [No response.]
5925 *The Clerk. Mr. Rulli?

5926 *Mr. Rulli. Aye.
5927 *The Clerk. Mr. Rulli votes aye.
5928 Mr. Evans?
5929 [No response.]
5930 *The Clerk. Mr. Evans?
5931 *Mr. Evans. Aye.
5932 *The Clerk. Mr. Evans votes aye.
5933 Mr. Goldman?
5934 [No response.]
5935 *The Clerk. Mrs. Fedorchak?
5936 [No response.]
5937 *The Clerk. Mr. Pallone?
5938 *Mr. Pallone. Aye.
5939 *The Clerk. Mr. Pallone votes aye.
5940 Ms. DeGette?
5941 *Ms. DeGette. Aye.
5942 *The Clerk. Ms. DeGette votes aye.
5943 Ms. Schakowsky?
5944 *Ms. Schakowsky. Aye.
5945 *The Clerk. Ms. Schakowsky votes aye.
5946 Ms. Matsui?
5947 *Ms. Matsui. Aye.
5948 *The Clerk. Ms. Matsui votes aye.
5949 Ms. Castor?
5950 *Ms. Castor. Aye.

5951 *The Clerk. Ms. Castor votes aye.
5952 Mr. Tonko?
5953 *Mr. Tonko. Aye.
5954 *The Clerk. Mr. Tonko votes aye.
5955 Ms. Clarke?
5956 *Ms. Clarke. Aye.
5957 *The Clerk. Ms. Clarke votes aye.
5958 Mr. Ruiz?
5959 *Mr. Ruiz. Aye.
5960 *The Clerk. Mr. Ruiz votes aye.
5961 Mr. Peters?
5962 *Mr. Peters. Aye.
5963 *The Clerk. Mr. Peters votes aye.
5964 Mrs. Dingell?
5965 [No response.]
5966 *The Clerk. Mr. Veasey?
5967 *Mr. Veasey. Aye.
5968 *The Clerk. Mr. Veasey votes aye.
5969 Ms. Kelly?
5970 *Ms. Kelly. Aye.
5971 *The Clerk. Ms. Kelly votes aye.
5972 Ms. Barragan?
5973 *Ms. Barragan. Aye.
5974 *The Clerk. Ms. Barragan votes aye.
5975 Mr. Soto?

5976 *Mr. Soto. Aye.
5977 *The Clerk. Mr. Soto votes aye.
5978 Ms. Schrier?
5979 *Ms. Schrier. Aye.
5980 *The Clerk. Ms. Schrier votes aye.
5981 Mrs. Trahan?
5982 *Mrs. Trahan. Aye.
5983 *The Clerk. Mrs. Trahan votes aye.
5984 Mrs. Fletcher?
5985 *Mrs. Fletcher. Aye.
5986 *The Clerk. Mrs. Fletcher votes aye.
5987 Ms. Ocasio-Cortez?
5988 [No response.]
5989 *The Clerk. Mr. Auchincloss?
5990 *Mr. Auchincloss. Aye.
5991 *The Clerk. Mr. Auchincloss votes aye.
5992 Mr. Carter of Louisiana?
5993 *Mr. Carter of Louisiana. Aye.
5994 *The Clerk. Mr. Carter of Louisiana votes aye.
5995 Mr. Menendez?
5996 *Mr. Menendez. Aye.
5997 *The Clerk. Mr. Menendez votes aye.
5998 Mr. Mullin?
5999 *Mr. Mullin. Aye.
6000 *The Clerk. Mr. Mullin votes aye.

6001 Mr. Landsman?

6002 *Mr. Landsman. Aye.

6003 *The Clerk. Mr. Landsman votes aye.

6004 Ms. McClellan?

6005 *Ms. McClellan. Aye.

6006 *The Clerk. Ms. McClellan votes aye.

6007 Chairman Guthrie?

6008 *The Chair. Aye.

6009 *The Clerk. Chairman Guthrie votes aye.

6010 *The Chair. Is anyone seeking -- Fedorchak? Mrs.

6011 Fedorchak, I am sorry.

6012 *The Clerk. Mrs. Fedorchak is not recorded.

6013 *Mrs. Fedorchak. Aye.

6014 *The Clerk. Mrs. Fedorchak votes aye.

6015 *The Chair. Mr. Obernolte?

6016 *Mr. Obernolte. Aye.

6017 *The Clerk. Mr. Obernolte votes aye.

6018 *The Chair. On the Democrat side, anyone?

6019 Maybe another minute or second, just to see. This is a

6020 big vote. Does anybody know somebody coming for this?

6021 All right, anybody on your side, do you think?

6022 *Voice. Mrs. Dingell.

6023 *The Chair. All right, seeing no one else.

6024 [Pause.]

6025 *The Chair. The clerk will report.

6026 *The Clerk. Mr. Chairman, on that vote there were 45
6027 ayes and 0 noes.

6028 *The Chair. The ayes have it, and the bill is adopted.
6029 I thank everybody for their hard work.

6030 The chair calls up H.R. 9390. I will say that again,
6031 9390, and asks the clerk to report.

6032 *The Clerk. H.R. 9390, a bill to amend title --

6033 *The Chair. Without objection, the first reading of the
6034 bill is dispensed with, and the bill will be open for
6035 amendment at any point.

6036 So ordered.

6037 [The bill follows:]

6038

6039 *****COMMITTEE INSERT*****

6040

6041 *The Chair. Does anyone seek to be recognized on the
6042 bill?

6043 For what purpose does the gentleman from New Jersey seek
6044 recognition?

6045 *Mr. Pallone. Thank you, Mr. Chairman. I know this
6046 bill is well intended --

6047 *The Chair. You are recognized for five minutes to
6048 speak on the bill.

6049 *Mr. Pallone. Thank you. I know this bill is well
6050 intended, but I want to speak in opposition.

6051 While I believe patients deserve transparency in the
6052 prices they pay for health care, I am very concerned that the
6053 bill will cause more confusion for consumers and become a
6054 barrier to care.

6055 And I also have strong concerns about the practicality
6056 of this proposal. The bill requires all hospitals,
6057 ambulatory surgical centers, laboratories, and imaging
6058 providers to post cash prices for health care services in
6059 publicly-accessible locations, and this includes hundreds and
6060 possibly thousands of procedure codes that providers would be
6061 required to post somewhere in their facilities, including on
6062 their walls. And I am concerned that requiring hospitals to
6063 post cash prices would deter patients from seeking care,
6064 particularly patients who qualify for financial assistance or
6065 who may be enrolled in health care coverage.

6066 According to a recent survey by the Kaiser Family
6067 Foundation, consumers already face significant barriers when
6068 trying to understand the out-of-pocket costs associated with
6069 their coverage. Requiring hospitals and providers to post
6070 cash prices, I think, is going to create more confusion for
6071 patients with health care coverage who may not fully
6072 understand their financial responsibilities or the
6073 implications of choosing to pay the cash price. Patients who
6074 choose to pay the cash price may also not realize that they
6075 are foregoing the Affordable Care Act's consumer protections
6076 such as the maximum out-of-pocket limit.

6077 Additionally, I am concerned about the practicality.
6078 Medical care is, frankly, complex and patients may face a
6079 variety of costs associated during the course of treatment.
6080 The final out-of-pocket cost will depend on a variety of
6081 factors, including the patient's diagnosis and their health
6082 insurance coverage. Even for patients who decide to pay the
6083 cash price, they are going to need to determine which
6084 procedure codes apply to them, and then they will have to
6085 determine which procedure and billing codes will be furnished
6086 as part of the service. The bill creates, I think, a false
6087 sense of transparency that will make it even more difficult
6088 for consumers who are already struggling to navigate and
6089 understand the costs of a health care procedure.

6090 Now, again, don't misunderstand. I know this is well

6091 intentioned, but I think that patients need transparency and
6092 it is unacceptable that some consumers are not able to easily
6093 obtain price information in advance. But I believe a more
6094 useful approach would be the policies in H.R. 393, and that
6095 is the one that requires hospitals and insurance companies to
6096 display charges online in a consumer-friendly way, including
6097 for shoppable services. And I think that ensures that
6098 patients have a clear understanding of their out-of-pocket
6099 costs before receiving care.

6100 So I urge my colleagues to support H.R. 393, obviously,
6101 and vote no on this bill. Thank you.

6102 *The Chair. Are there any further discussion on the
6103 Republican side?

6104 Seeing none, are there any amendments?

6105 The gentlelady from Iowa is recognized -- oh, for what
6106 purpose does the gentlelady from Iowa seek recognition?

6107 *Mrs. Miller-Meeks. I --

6108 *The Chair. Do you have an amendment at the desk?

6109 *Mrs. Miller-Meeks. Mr. Chair, I have an amendment at
6110 the desk with the file name H9390-EC-FC-ANS_01_XML.

6111 *The Chair. The clerk will report.

6112 *The Clerk. The amendment in the nature of a substitute
6113 to H.R. --

6114 *The Chair. Without objection, the reading of the
6115 amendment is dispensed with.

6116 [The amendment of Mrs. Miller-Meeks follows:]

6117

6118 *****COMMITTEE INSERT*****

6119

6120 *The Chair. And the gentlelady is recognized for five
6121 minutes in support of the amendment.

6122 *Mrs. Miller-Meeks. Thank you, Mr. Chairman. I would
6123 like to speak in support of both the ANS to H.R. 9390, the
6124 Prices on the Wall Act of 2026, and the underlying bill.

6125 For most purchases Americans make every day, the price
6126 comes first. Whether you are buying groceries, filling your
6127 gas tank, even if you are getting your car repaired, you know
6128 what something costs before you decide it. And it seems to
6129 me that the technology in a smartphone and the pricing is a
6130 lot more challenging than this. Health care should not be an
6131 exception.

6132 As a physician, I have seen firsthand how uncertainty
6133 over medical bills creates unnecessary stress for patients
6134 and their families. Too often, people receive care without
6135 having any meaningful idea of what it will cost until the
6136 bill arrives weeks or even months later. The Prices on the
6137 Wall Act addresses that problem with a simple, practical
6138 solution: starting in 2028 hospitals, ambulatory surgery
6139 centers, laboratory, and imaging providers with -- post
6140 pricing information for commonly shoppable services in
6141 locations where patients can easily see it before receiving
6142 care. Facilities would display discounted cash prices
6143 whenever available, or other clear, consumer-friendly pricing
6144 information.

6145 This legislation does not ask patients to search through
6146 complicated websites or decipher technical billing data. It
6147 puts useful pricing information where it belongs: in front
6148 of patients when they are making decisions about their care.

6149 Greater transparency benefits everyone. Patients are
6150 better equipped to compare options, providers have greater
6151 incentives to compete on value, and our health care system
6152 becomes much more accountable to the people it serves. This
6153 is a straightforward reform built on a principle Americans
6154 already expect through the rest of the economy: consumers
6155 deserve to know the price before they make a purchase.

6156 I appreciate the committee's consideration of this
6157 legislation, and I urge my colleagues to support H.R. 9390,
6158 the Prices on the Wall Act.

6159 And I yield back.

6160 *The Chair. The gentlelady yields back. Is there
6161 further discussion?

6162 Seeing none, the vote occurs on the amendment.

6163 All those in favor shall signify by saying aye.

6164 Those opposed, no.

6165 The ayes have it, and the amendment is agreed to. Are
6166 there any further amendments?

6167 Seeing none, the question now occurs on adopting H.R.
6168 9390, as amended. A roll call has been requested and the
6169 clerk will call the roll.

6170 *The Clerk. Mr. Latta?
6171 *Mr. Latta. Aye.
6172 *The Clerk. Mr. Latta votes aye.
6173 Mr. Griffith?
6174 *Mr. Griffith. Aye.
6175 *The Clerk. Mr. Griffith votes aye.
6176 Mr. Bilirakis?
6177 *Mr. Bilirakis. Aye.
6178 *The Clerk. Mr. Bilirakis votes aye.
6179 Mr. Hudson?
6180 *Mr. Hudson. Aye.
6181 *The Clerk. Mr. Hudson votes aye.
6182 Mr. Carter of Georgia?
6183 *Mr. Carter of Georgia. Aye.
6184 *The Clerk. Mr. Carter of Georgia votes aye.
6185 Mr. Palmer?
6186 [No response.]
6187 *The Clerk. Mr. Dunn?
6188 [No response.]
6189 *The Clerk. Mr. Crenshaw?
6190 [No response.]
6191 *The Clerk. Mr. Joyce?
6192 *Mr. Joyce. Aye.
6193 *The Clerk. Mr. Joyce votes aye.
6194 Mr. Weber?

6195 [No response.]
6196 *The Clerk. Mr. Allen?
6197 [No response.]
6198 *The Clerk. Mr. Balderson?
6199 *Mr. Balderson. Aye.
6200 *The Clerk. Mr. Balderson votes aye.
6201 Mr. Fulcher?
6202 *Mr. Fulcher. Fulcher is aye.
6203 *The Clerk. Mr. Fulcher votes aye.
6204 Mr. Pfluger?
6205 *Mr. Pfluger. Aye.
6206 *The Clerk. Mr. Pfluger votes aye.
6207 Mrs. Harshbarger?
6208 *Mrs. Harshbarger. Aye.
6209 *The Clerk. Mrs. Harshbarger votes aye.
6210 Mrs. Miller-Meeks?
6211 *Mrs. Miller-Meeks. Yes.
6212 *The Clerk. Mrs. Miller-Meeks votes aye.
6213 Mrs. Cammack?
6214 [No response.]
6215 *The Clerk. Mr. Obernolte?
6216 *Mr. Obernolte. Aye.
6217 *The Clerk. Mr. Obernolte votes aye.
6218 Mr. James?
6219 *Mr. James. Aye.

6220 *The Clerk. Mr. James votes aye.
6221 Mr. Bentz?
6222 *Mr. Bentz. Aye.
6223 *The Clerk. Mr. Bentz votes aye.
6224 Mrs. Houchin?
6225 [No response.]
6226 *The Clerk. Mr. Fry?
6227 [No response.]
6228 *The Clerk. Ms. Lee?
6229 [No response.]
6230 *The Clerk. Mr. Langworthy?
6231 *Mr. Langworthy. Aye.
6232 *The Clerk. Mr. Langworthy votes aye.
6233 Mr. Kean?
6234 [No response.]
6235 *The Clerk. Mr. Rulli?
6236 *Mr. Rulli. Aye.
6237 *The Clerk. Mr. Rulli votes aye.
6238 Mr. Evans?
6239 *Mr. Evans. Aye.
6240 *The Clerk. Mr. Evans votes aye.
6241 Mr. Goldman?
6242 *Mr. Goldman. Aye.
6243 *The Clerk. Mr. Goldman votes aye.
6244 Mrs. Fedorchak?

6245 *Mrs. Fedorchak. Aye.
6246 *The Clerk. Mrs. Fedorchak votes aye.
6247 Mr. Pallone?
6248 *Mr. Pallone. No.
6249 *The Clerk. Mr. Pallone votes no.
6250 Ms. DeGette?
6251 *Ms. DeGette. No.
6252 *The Clerk. Ms. DeGette votes no.
6253 Ms. Schakowsky?
6254 *Ms. Schakowsky. No.
6255 *The Clerk. Ms. Schakowsky votes no.
6256 Ms. Matsui?
6257 *Ms. Matsui. No.
6258 *The Clerk. Ms. Matsui votes no.
6259 Ms. Castor?
6260 *Ms. Castor. No.
6261 *The Clerk. Ms. Castor votes no.
6262 Mr. Tonko?
6263 *Mr. Tonko. No.
6264 *The Clerk. Mr. Tonko votes no.
6265 Ms. Clarke?
6266 *Ms. Clarke. No.
6267 *The Clerk. Ms. Clarke votes no.
6268 Mr. Ruiz?
6269 *Mr. Ruiz. No.

6270 *The Clerk. Mr. Ruiz votes no.
6271 Mr. Peters?
6272 *Mr. Peters. No.
6273 *The Clerk. Mr. Peters votes no.
6274 Mrs. Dingell?
6275 [No response.]
6276 *The Clerk. Mr. Veasey?
6277 [No response.]
6278 *The Clerk. Ms. Kelly?
6279 *Ms. Kelly. No.
6280 *The Clerk. Ms. Kelly votes no.
6281 Ms. Barragan?
6282 *Ms. Barragan. No.
6283 *The Clerk. Ms. Barragan votes no.
6284 Mr. Soto?
6285 *Mr. Soto. No.
6286 *The Clerk. Mr. Soto votes no.
6287 Ms. Schrier?
6288 *Ms. Schrier. No.
6289 *The Clerk. Ms. Schrier votes no.
6290 Mrs. Trahan?
6291 *Mrs. Trahan. No.
6292 *The Clerk. Mrs. Trahan votes no.
6293 Mrs. Fletcher?
6294 *Mrs. Fletcher. No.

6295 *The Clerk. Mrs. Fletcher votes no.
6296 Ms. Ocasio-Cortez?
6297 [No response.]
6298 *The Clerk. Mr. Auchincloss?
6299 *Mr. Auchincloss. No.
6300 *The Clerk. Mr. Auchincloss votes no.
6301 Mr. Carter of Louisiana?
6302 *Mr. Carter of Louisiana. No.
6303 *The Clerk. Mr. Carter of Louisiana votes no.
6304 Mr. Menendez?
6305 *Mr. Menendez. No.
6306 *The Clerk. Mr. Menendez votes no.
6307 Mr. Mullin?
6308 *Mr. Mullin. No.
6309 *The Clerk. Mr. Mullin votes no.
6310 Mr. Landsman?
6311 *Mr. Landsman. No.
6312 *The Clerk. Mr. Landsman votes no.
6313 Ms. McClellan?
6314 *Ms. McClellan. No.
6315 *The Clerk. Ms. McClellan votes no.
6316 Chairman Guthrie?
6317 *The Chair. Aye.
6318 *The Clerk. Chairman Guthrie votes aye.
6319 *Mr. Weber. How is Mr. Weber --

6320 *The Clerk. Mr. Weber is not recorded.
6321 *Mr. Weber. Weber votes aye.
6322 *The Clerk. Mr. Weber votes aye.
6323 *The Chair. Mrs. Houchin?
6324 *The Clerk. Mrs. Houchin is not recorded.
6325 *Mrs. Houchin. Houchin votes aye.
6326 *The Chair. How is Mr. Palmer --
6327 *The Clerk. Mrs. Houchin votes aye.
6328 *The Chair. -- of Alabama recorded?
6329 *The Clerk. Mr. Palmer is not recorded.
6330 *Mr. Palmer. Palmer votes aye.
6331 *The Clerk. Mr. Palmer votes aye.
6332 *The Chair. Is there anyone on your side?
6333 [Pause.]
6334 *The Chair. How is Mr. Allen recorded?
6335 *The Clerk. Mr. Allen is not recorded.
6336 *Mr. Allen. Aye.
6337 *The Clerk. Mr. Allen votes aye.
6338 *The Chair. The clerk will -- seeing no others for --
6339 being in the roll call, the clerk will report.
6340 *The Clerk. Mr. Chairman, on that vote there were 24
6341 ayes and 21 noes.
6342 *The Chair. The ayes have it, and the bill is adopted.
6343 The chair calls up H.R. 1266, and asks the clerk to
6344 report.

6345 *The Clerk. H.R. 1266, a bill to prohibit certain uses
6346 of Xylazine, and for other purposes. Be it enacted by the
6347 Senate and House of Representatives of the United States of
6348 America and Congress assembled. Section 1, short title.
6349 This title may --

6350 *The Chair. Without objection, the first reading of the
6351 bill is dispensed with, and the bill will be open for
6352 amendment at any point.

6353 So ordered.

6354 [The bill follows:]

6355

6356 *****COMMITTEE INSERT*****

6357

6358 *The Chair. Does anyone seek to be recognized on the
6359 bill?

6360 The gentleman from Texas is recognized for five minutes
6361 to speak on the bill.

6362 *Mr. Pfluger. Yes, Mr. Chair, I do have an amendment.
6363 I am sorry, are we at that point? An amendment to
6364 H1266_FCR_ANS?

6365 *The Chair. So no one to speak on the bill, so there --
6366 we will speak on the ANS. So the gentleman -- we can call up
6367 the ANS.

6368 Do you want to speak on the -- so we are going to speak
6369 on the ANS as the bill. Is that okay? That is fine. So the
6370 gentleman -- the clerk will report.

6371 Everybody will have their chance to speak.

6372 *The Clerk. Amendment in the nature of a substitute to
6373 H.R. 1266 offered by Mr. Pfluger of Texas.

6374 *The Chair. Without objection, the reading of the
6375 amendment is dispensed with.

6376 [The amendment of Mr. Pfluger follows:]

6377

6378 *****COMMITTEE INSERT*****

6379

6380 *The Chair. And the gentleman is recognized for five
6381 minutes in support of the amendment. The gentleman is
6382 recognized.

6383 *Mr. Pfluger. Thank you, Mr. Chairman.

6384 Moving this bill has been a top priority alongside
6385 Congressman Panetta since 2023. And after three years of
6386 work, I am proud to see that this is moving in a bipartisan
6387 way.

6388 We all know that the drug crisis in this country is
6389 becoming more and more tragic, with traffickers turning to an
6390 important veterinarian tranquilizer to make drugs more
6391 addictive and more deadly. Xylazine has emerged as an
6392 increasingly popular substance to cut fentanyl with to
6393 intensify drug effects and to lower the cost. But because
6394 Xylazine is not currently scheduled under the Controlled
6395 Substances Act, dealers and traffickers can purchase it
6396 online for as little as \$6 per kilogram.

6397 The effects of Xylazine are devastating, including
6398 several skin wounds that often lead to amputation and severe
6399 withdrawal symptoms that leave users trapped in a vicious
6400 cycle of addiction. According to a recent CDC report,
6401 Xylazine was involved in over 6,000 drug poisoning deaths in
6402 2023, making it the fourth most common substance in drug
6403 poisoning fatalities in this country. DEA labs shows
6404 Xylazine present in over 25 percent of fentanyl powder

6405 exhibits, and over 8 percent of all pill exhibits. And
6406 because Xylazine is not an opioid, Naloxone cannot reverse
6407 its effects when someone overdoses.

6408 Despite these alarming trends, Federal, state, and local
6409 law enforcement do not have the necessary tools to
6410 effectively track Xylazine or crack down on traffickers using
6411 it to increase their profits. Twenty-nine states have
6412 already considered restrictions on Xylazine, and sixteen have
6413 enacted their own, creating a growing patchwork of
6414 inconsistent laws that actually hurts the effects of law
6415 enforcement, as well as veterinarians. Only Congress can fix
6416 this with a uniform national framework.

6417 Our bill permanently places illicit Xylazine under
6418 schedule 3 of the Controlled Substances Act, giving law
6419 enforcement the tools to track distribution and crack down on
6420 trafficking, while carefully preserving the critical role it
6421 plays in veterinarian medicine. Veterinarians, farmers,
6422 ranchers, and wildlife personnel all rely on Xylazine, but
6423 for cattle specifically there is simply no safe, practical
6424 alternative at all.

6425 This is not a bill we wrote in a vacuum. It reflects
6426 three years of direct work with DEA, DoJ, and HHS under two
6427 different administrations. And without the statutory changes
6428 in our bill, DEA cannot amend the ultimate user definition to
6429 protect veterinarians, farmers, and ranchers, and cannot

6430 bring Xylazine into ARCOS reporting, their automated,
6431 comprehensive drug reporting system that tracks every step of
6432 the supply chain from manufacturing to point of sale.

6433 Administrative scheduling alone cannot get the job done.
6434 Congressional action now is the only path forward. The
6435 fentanyl crisis has already inflicted significant damage on
6436 our treatment clinics, our public health agencies, and our
6437 entire medical system. The addition of yet another highly
6438 toxic substance to illicit drug supply has only escalated
6439 this crisis. That is why this bill has earned support from
6440 the DEA, the FDA, and both the previous and the current
6441 administrations, nearly 80 percent of state attorneys
6442 general, and all 50 state veterinarian medical associations,
6443 and the American Farm Bureau.

6444 I want to thank Congressmen Panetta and Bilirakis for
6445 their partnership in this effort. Scheduling Xylazine while
6446 protecting its critical veterinarian use is a responsible
6447 approach, and I urge my colleagues to vote yes.

6448 I yield back.

6449 *Mr. Griffith. [Presiding.] Is anyone else speaking to
6450 the amendment?

6451 I recognize the gentlelady from Massachusetts, Mrs.
6452 Trahan.

6453 *Mrs. Trahan. I am sorry, I am waiting for the
6454 amendment to be offered. I will speak on that.

6455 *Mr. Griffith. You are waiting for the additional
6456 amendment?

6457 *Mrs. Trahan. Yes.

6458 *Mr. Griffith. Okay, fair enough. I recognize the
6459 gentleman from Georgia, Mr. Carter.

6460 *Mr. Carter of Georgia. Thank you, Mr. Chairman. Thank
6461 you, Mr. Chairman. Mr. Chairman, I move to strike the last
6462 word.

6463 *Mr. Griffith. The gentleman is recognized to speak on
6464 the amendment in the nature of substitute.

6465 *Mr. Carter of Georgia. Mr. Chairman, I speak today in
6466 strong support of the Combating Illicit Xylazine Act,
6467 legislation that I am proud to have originally cosponsored.

6468 As a pharmacist, I have spent my career focused on
6469 protecting patients, ensuring medications are used safely and
6470 appropriately. Unfortunately, criminals have taken a
6471 veterinary medicine that serves an important purpose and
6472 turned it into another deadly weapon in illicit drug supply.
6473 Communities across Georgia and across our nation are seeing
6474 the consequences firsthand. First responders, emergency
6475 physicians, and law enforcement officers are confronting
6476 overdoses that are more difficult to treat while families
6477 continue to lose loved ones to an increasingly toxic and
6478 unpredictable drug supply.

6479 We cannot afford to stand by while traffickers exploit

6480 another loophole to make their poison even deadlier. The
6481 Combating Illicit Xylazine Act targets those who manufacture,
6482 import, and trafficking illicit Xylazine while preserving
6483 access for veterinarians, ranchers, livestock producers.

6484 We should never force our agriculture community to bear
6485 the burden of criminal misuse, and this legislation ensures
6486 that they won't have to.

6487 This bill also gives Federal law enforcement another
6488 important tool to disrupt the criminal organizations
6489 responsible for flooding our communities with dangerous
6490 synthetic drugs. We know these organizations constantly
6491 adapt, looking for new substances to increase addiction,
6492 stretch their supply, and maximize profits. Congress must be
6493 just as determined to stay ahead of them.

6494 I am especially proud that this legislation reflects a
6495 bipartisan commitment to addressing the opioid crisis with
6496 practical, targeted solutions. This is not about creating
6497 unnecessary regulations; it is about recognizing a growing
6498 threat and responding before even more lives are lost.

6499 I know medications can save lives when used
6500 appropriately, but in the hands of drug traffickers
6501 substances like Xylazine become instruments of tragedy. As
6502 Members of Congress, we have a responsibility to stop the
6503 criminal diversion of these drugs while protecting legitimate
6504 medical and veterinary use.

6505 I urge my colleagues to support this legislation and I
6506 yield back.

6507 *Mr. Griffith. The gentleman yields back. Is anyone
6508 else speaking to the ANS?

6509 I recognize the gentleman from Louisiana, Mr. Carter.

6510 *Mr. Carter of Louisiana. I move to strike the last
6511 word. Chairman, the gentleman -- I would like to speak in
6512 support of H.R. 1266, the Combating Illicit Xylazine Act, led
6513 by Representatives Panetta and Pfluger.

6514 I am proud to represent New Orleans, home of world-class
6515 institutions like Tulane University, LSU Health, and many
6516 others, where groundbreaking biomedical research is happening
6517 every day. Xylazine plays a critical role in that work,
6518 serving as one of the most used injectable sedatives in
6519 transitional medicine. Any disruption in the availability of
6520 this FDA-approved drug or its removal from the market would
6521 complicate ongoing research studies happening at leading
6522 research institutions in my district and across the United
6523 States.

6524 Limiting its use would also slow down scientific
6525 progress, and researchers look to alternatives and the -- and
6526 assess the impacts of changes in the studies that are
6527 currently ongoing. I believe in -- Combating Illicit
6528 Xylazine Act targets the illegal use of Xylazine while
6529 maintaining access for veterinarians and researchers to use

6530 the drug for legitimate medical and research purposes that
6531 help drive innovation and improve health outcomes in the
6532 United States. If Congress does not step in, this puts
6533 animal welfare and humans at -- safety at risk.

6534 Lastly, the bill would also provide regulatory clarity
6535 and uniformity for manufacturers, distributors, and
6536 veterinarians who are navigating a complicated patchwork of
6537 state laws to regulate Xylazine.

6538 I encourage my colleagues to join me in supporting this
6539 legislation.

6540 Thank you, I yield back.

6541 *Mr. Griffith. The gentleman yields back. Is anyone
6542 else speaking to the ANS?

6543 All right. Seeing none, we can -- there is amendment.
6544 Do we do that before we vote on it? Okay. So we now have --
6545 we will entertain amendments to the amendment in the nature
6546 of a substitute, and I recognize the gentlelady from
6547 Illinois, Ms. Kelly.

6548 *Ms. Kelly. Thank you, Mr. Chair.

6549 *Mr. Griffith. Please identify your amendment first.

6550 *Ms. Kelly. Oh, sorry.

6551 *Mr. Griffith. My fault. I should have -- I recognized
6552 you to speak on it, but we haven't identified it yet.

6553 Can the clerk identify Ms. Kelly's amendment?

6554 *The Clerk. Amendment to the amendment in the nature of

6555 a substitute to H.R. 1266 offered by Ms. Kelly of Illinois.

6556 [The amendment of Ms. Kelly follows:]

6557

6558 *****COMMITTEE INSERT*****

6559

6560 *Mr. Griffith. The gentlelady may state her amendment.

6561 *Ms. Kelly. Thank you, Mr. Chair.

6562 I filed this amendment in collaboration with
6563 Congresswoman DeGette, who has worked tirelessly to improve
6564 our public health response to substance use and the opioid
6565 epidemic. This amendment would move Xylazine to a schedule 5
6566 drug under the Controlled Substances Act, rather than a
6567 schedule 3 drug, where the current legislation has it placed.

6568 As many of you are aware, schedule 3 drug possession
6569 carries felony charges and up to 10 years of prison time,
6570 whereas a schedule 5 drug possession charge is a misdemeanor.
6571 This difference cannot be understated (sic) when it comes to
6572 helping people with substance use disorders. While I support
6573 the bipartisan effort of this committee and Congress to
6574 remove a dangerous substance off our streets while protecting
6575 its appropriate veterinary uses, higher penalties for those
6576 with addiction will only exacerbate our drug problems.

6577 We know that criminalization of drug use does not reduce
6578 drug use. It can even disrupt the evidence-based harm
6579 reduction drug -- harm reduction strategies and behaviors
6580 that actually help our communities, especially people of
6581 color. This attempted increase in drug use criminalization
6582 is occurring all while the current Administration is rolling
6583 back funding for harm reduction and substance use treatment
6584 across the country.

6585 Xylazine can be incredibly dangerous to the people that
6586 use drugs, especially when unknown to drug users. It is
6587 mixed in with fentanyl, which occurs in more than 99 percent
6588 of instances. However, fentanyl use already carries schedule
6589 2 penalties. A change in scheduling is common sense and
6590 based on scientific evidence. An unreleased HHS review
6591 recommended that Xylazine be classified as a schedule 5 drug,
6592 which was mentioned by my colleague, Congresswoman DeGette,
6593 in the subcommittee markup. Excluding this science-based
6594 recommendation could lead to more harm than good.

6595 This amendment is an appropriate change to keep our
6596 community safe and helping those with drug addiction. Now
6597 more than ever we must continue to follow evidence-based
6598 science to make everyone safe and healthy.

6599 Thank you, and I yield --

6600 *Ms. DeGette. Will the gentlelady yield?

6601 *Ms. Kelly. Yes, I will.

6602 *Ms. DeGette. Thank you. I thank the gentlelady for
6603 offering this amendment. It really puts science before
6604 politics. And as she said, it relieves burdens on the
6605 criminal justice system.

6606 By amending the bill to put Xylazine in schedule 5
6607 instead of schedule 3, it gives the DEA the authority to
6608 track and prosecute illegal drugs while not over-
6609 criminalizing low-level drug offenders.

6610 As the -- as my friend mentioned, HHS and DEA
6611 recommended schedule 5 in their scientific analysis, which
6612 Congress has yet to receive and which we asked for in the
6613 subcommittee hearing. And the reason why they do this
6614 analysis as a pre-requisite to scheduling a substance is
6615 because the cost of over-scheduling takes the form of an
6616 over-burdened judicial system, and it takes real tolls on the
6617 communities across the country.

6618 I support scheduling Xylazine, and I also support a
6619 statutory fix to ensure veterinarians can maintain access to
6620 this essential tranquilizer for legitimate purposes. But I
6621 also -- I served in the state legislature for some time in
6622 Colorado before I came here, and I saw what happened when
6623 people over-schedule or over-penalize offenses, and that is
6624 it just adds to the burdens of our system while not
6625 addressing the real risks.

6626 And so I think what we need to do is to get the actual
6627 study that was done and to base our legislation on science
6628 and facts, and so that is why I support the gentlelady's
6629 amendment.

6630 And I yield back.

6631 *Mr. Griffith. The gentlelady yields back. Does the
6632 gentlelady yield back?

6633 *Ms. Kelly. Yes, I do.

6634 *Mr. Griffith. So the gentlelady yields back to the

6635 gentlelady who yielded back to the chair.

6636 *Ms. DeGette. I yield back to the gentlelady.

6637 *Mr. Griffith. Yes, got it. I now recognize the
6638 gentleman from Texas, Mr. Pfluger.

6639 *Mr. Pfluger. Yes, well, I appreciate my colleague,
6640 Congresswoman Kelly, for -- I think we all believe that this
6641 is -- something that needs to be done. I just kind of want
6642 to, you know, get back to the root of this.

6643 And obviously, I have a strong opposition to this
6644 amendment because I do think it would weaken the bill by
6645 lowering the schedule from 3 to 5. Placing it in schedule 3
6646 has been a product of extensive bipartisan work for many
6647 years -- as I said, three years. And this policy is
6648 supported by both HHS and DEA, and it has received support
6649 from both the Biden and the Trump Administrations, those
6650 entities in both Administrations.

6651 In fact, the Biden Administration repeatedly called for
6652 Xylazine to be placed at schedule 3, not schedule 5. And
6653 several years ago HHS also considered schedule 5 as part of
6654 its 8-point scheduling process. The previous administration
6655 moved past that early thought, and then ultimately endorsed
6656 our bill's schedule 3 approach. The Biden Administration's
6657 own detect-and-defeat proposal included the same schedule 3
6658 language found in this bill, further confirming the schedule
6659 3, not schedule 5, was considered their final position.

6660 So I think, you know, when we are looking at this
6661 amendment, this unfounded, I think, hesitation about placing
6662 it in schedule 3 really could jeopardize what we are trying
6663 to do here, which is solve a problem that is pretty complex.

6664 And I want to enter a letter into the record, Mr.
6665 Chairman, from the HHS Assistant Secretary for Legislation.
6666 It is the position of HHS that they believe "legislatively
6667 scheduling Xylazine into schedule 3 is appropriate to
6668 institute clear, meaningful controls, given the dangers posed
6669 by Xylazine as an adulterant in the illicit market''.

6670 *Mr. Griffith. And the date of the letter is?

6671 *Mr. Pfluger. I don't have the date of the letter, but
6672 I will get the date to you.

6673 *Mr. Griffith. All right.

6674 *Mr. Pfluger. So --

6675 *Mr. Griffith. Without objection? Is there an
6676 objection?

6677 You want to know the date.

6678 *Ms. DeGette. Reserving the right to object.

6679 *Mr. Griffith. We will hold it.

6680 *Mr. Pfluger. Thank you.

6681 *Mr. Griffith. We will hold it until both sides have
6682 had a chance to look at it --

6683 *Ms. DeGette. I can sense --

6684 *Mr. Griffith. -- and see the letter.

6685 *Ms. DeGette. -- the chairman wants the date, so --

6686 *Mr. Griffith. I do. I generally like the date, you
6687 are right.

6688 *Mr. Pfluger. Okay.

6689 *Mr. Griffith. Sorry.

6690 *Mr. Pfluger. Thank you. Back to the point, moving
6691 Xylazine to schedule 5 would do nothing but weaken the tools
6692 that prosecutors and law enforcement need to go after
6693 traffickers, and that only helps the people profiting off
6694 this crisis. Yes, some similar drugs are listed as schedule
6695 5, but scheduling isn't just about which category a drug
6696 falls into. It is also about how dangerous a drug is. And
6697 Xylazine's abuse and dependency risk is exactly why it
6698 belongs in schedule 3.

6699 Given that Xylazine is now found in 49 of 50 states and
6700 in nearly one-third of all fentanyl powder seized by DEA, my
6701 bill as drafted will help lead to safer communities across
6702 the U.S., and I think that this amendment would only
6703 undermine that bipartisan work that we have done to ensure
6704 that DEA has the ability to combat the increasing threat of
6705 Xylazine.

6706 Therefore, I urge all of my colleagues to vote no on
6707 this amendment, but to vote in the affirmative on the
6708 schedule 3.

6709 I yield back.

6710 *Mr. Griffith. The gentleman yields back. Are there
6711 others wishing to address the amendment, the Kelly amendment?

6712 Is anyone else wanting to address the Kelly amendment?

6713 I recognize Mrs. Trahan of Massachusetts for her time to
6714 talk on the amendment.

6715 *Mrs. Trahan. Thank you, Mr. Chairman.

6716 I am glad that this committee is coming together in a
6717 bipartisan way in support of the Combating Illicit Xylazine
6718 Act. It is an Act that I cosponsor, and I am proud to do it.

6719 Xylazine is a genuine and growing danger in the illicit
6720 drug supply. It heightens the sedation and respiratory
6721 depression caused by opioids. It makes emergency overdose
6722 reversal drugs like Naloxone less effective, and it causes
6723 severe necrotic wounds that too often end in amputation.

6724 Xylazine has already reshaped the drug supply back home
6725 in Massachusetts. State data shows Xylazine turned up in
6726 roughly one in five tested street drug samples last year, and
6727 the Merrimack Valley, which I hail from, has felt it. Our
6728 local law enforcement has been blowing the whistle on
6729 Xylazine for years, a warning I raised in this committee
6730 three years ago.

6731 This drug is actively making the overdose crisis harder
6732 to survive and harder to treat. A threat like that, it just
6733 demands a scheduling decision matching its severity. And
6734 that is why I support the bill as written, and why I will be

6735 voting against the amendment, because I just want us to
6736 consider the alternative: schedule 5 covers products like
6737 Robitussin, medicines with limited abuse potential and
6738 minimal public health risks. Xylazine, by every measure we
6739 have just discussed, is not that. Placing it in the same
6740 tier as cough syrup would understate the danger it poses on
6741 our streets today.

6742 And it is true that President Biden's HHS initially
6743 recommended schedule 5, but that recommendation was one step
6744 in an evolving, iterative process. It wasn't the final word.
6745 The Office of National Drug Control Policy under the same
6746 administration called for schedule 3. And when HHS and DoJ
6747 took up the question again under this Administration, they
6748 too arrived at schedule 3.

6749 So given the dangers Xylazine presents to our
6750 communities, I think the bill before us gets it right. And
6751 that is why I will be voting to support the bill and to
6752 preserve the schedule 3 classification.

6753 *Ms. Barragan. Will the gentlewoman yield?

6754 *Mrs. Trahan. Happily, yes.

6755 *Ms. Barragan. I want to associate my remarks with your
6756 remarks and your reasoning on why I also will be voting no on
6757 the amendment. Thank you.

6758 *Mrs. Trahan. Thank you.

6759 I yield back.

6760 *Mr. Griffith. The gentlelady yields back, and I now
6761 recognize the gentleman from Georgia, Mr. Carter.

6762 *Mr. Carter of Georgia. Mr. Chairman, I want to call on
6763 my experience as a pharmacist for over 40 years in the State
6764 of Georgia. A schedule 5 drug can be signed for in the State
6765 of Georgia. This would be a terrible idea to classify this
6766 as schedule 5, and I hope everyone realizes that, and I hope
6767 that we will vote this amendment down because this is not
6768 what we are trying to do here in addressing this serious
6769 problem that is afflicting our communities, and it needs to
6770 be addressed.

6771 So I encourage everyone to vote against this amendment,
6772 and I yield back.

6773 *Mr. Griffith. The gentleman yields back.

6774 I now have the letter dated March 24, 2026 addressed to
6775 the Honorable Brett Guthrie from the Department of HHS, and
6776 signed by Gary Andres. Is there any objection to that being
6777 entered into the record?

6778 *Ms. DeGette. I withdraw my reservation.

6779 *Mr. Griffith. The gentlelady withdraws her
6780 reservation, and it is admitted into the record without
6781 objection.

6782

6783

6784

6785 [The information follows:]

6786

6787 *****COMMITTEE INSERT*****

6788

6789 *Mr. Griffith. Is anyone else wishing to speak to the
6790 amendment?

6791 Seeing none, all those in favor of the amendment, say
6792 aye.

6793 All opposed, no.

6794 The noes have it. The amendment is defeated.

6795 Now we have to vote on the amendment in the nature of a
6796 substitute, assuming there are no other amendments.

6797 Seeing none, all right, we will now vote on the
6798 amendment in the nature substitute and -- no, we vote on the
6799 amendment in the nature of a substitute, the language.

6800 So all those in favor, say aye.

6801 All opposed, no.

6802 The amendment in the nature of a substitute is adopted.

6803 Now we vote on the underlying bill, as amended. A roll
6804 call has been requested. The clerk will please call the
6805 roll.

6806 *The Clerk. Mr. Latta?

6807 *Mr. Latta. Aye.

6808 *The Clerk. Mr. Latta votes aye.

6809 Mr. Griffith?

6810 *Mr. Griffith. Aye.

6811 *The Clerk. Mr. Griffith votes aye.

6812 Mr. Bilirakis?

6813 *Mr. Bilirakis. Aye.

6814 *The Clerk. Mr. Bilirakis votes aye.
6815 Mr. Hudson?
6816 *Mr. Hudson. Aye.
6817 *The Clerk. Mr. Hudson votes aye.
6818 Mr. Carter of Georgia?
6819 *Mr. Carter of Georgia. Aye.
6820 *The Clerk. Mr. Carter of Georgia votes aye.
6821 Mr. Palmer?
6822 *Mr. Palmer. Palmer votes aye.
6823 *The Clerk. Mr. Palmer votes aye.
6824 Mr. Dunn?
6825 [No response.]
6826 *The Clerk. Mr. Crenshaw?
6827 [No response.]
6828 *The Clerk. Mr. Joyce?
6829 *Mr. Joyce. Aye.
6830 *The Clerk. Mr. Joyce votes aye.
6831 Mr. Weber?
6832 [No response.]
6833 *The Clerk. Mr. Allen?
6834 *Mr. Allen. Aye.
6835 *The Clerk. Mr. Allen votes aye.
6836 Mr. Balderson?
6837 *Mr. Balderson. Aye.
6838 *The Clerk. Mr. Balderson votes aye.

6839 Mr. Fulcher?
6840 *Mr. Fulcher. Fulcher is aye.
6841 *The Clerk. Mr. Fulcher votes aye.
6842 Mr. Pfluger?
6843 *Mr. Pfluger. Aye.
6844 *The Clerk. Mr. Pfluger votes aye.
6845 Mrs. Harshbarger?
6846 *Mrs. Harshbarger. Aye.
6847 *The Clerk. Mrs. Harshbarger votes aye.
6848 Mrs. Miller-Meeks?
6849 *Mrs. Miller-Meeks. Yes.
6850 *The Clerk. Mrs. Miller-Meeks votes aye.
6851 Mrs. Cammack?
6852 [No response.]
6853 *The Clerk. Mr. Obernolte?
6854 [No response.]
6855 *The Clerk. Mr. James?
6856 *Mr. James. Aye.
6857 *The Clerk. Mr. James votes aye.
6858 Mr. Bentz?
6859 *Mr. Bentz. Aye.
6860 *The Clerk. Mr. Bentz votes aye.
6861 Mrs. Houchin?
6862 [No response.]
6863 *The Clerk. Mr. Fry?

6864 [No response.]
6865 *The Clerk. Ms. Lee?
6866 *Ms. Lee. Aye.
6867 *The Clerk. Ms. Lee votes aye.
6868 Mr. Langworthy?
6869 *Mr. Langworthy. Aye.
6870 *The Clerk. Mr. Langworthy votes aye.
6871 Mr. Kean?
6872 *Mr. Kean. Aye.
6873 *The Clerk. Mr. Kean votes aye.
6874 Mr. Rulli?
6875 *Mr. Rulli. Aye.
6876 *The Clerk. Mr. Rulli votes aye.
6877 Mr. Evans?
6878 *Mr. Evans. Aye.
6879 *The Clerk. Mr. Evans votes aye.
6880 Mr. Goldman?
6881 *Mr. Goldman. Aye.
6882 *The Clerk. Mr. Goldman votes aye.
6883 Mrs. Fedorchak?
6884 *Mrs. Fedorchak. Aye.
6885 *The Clerk. Mrs. Fedorchak votes aye.
6886 Mr. Pallone?
6887 *Mr. Pallone. Aye.
6888 *The Clerk. Mr. Pallone votes aye.

6889 Ms. DeGette?
6890 *Ms. DeGette. Aye.
6891 *The Clerk. Ms. DeGette votes aye.
6892 Ms. Schakowsky?
6893 *Ms. Schakowsky. Aye.
6894 *The Clerk. Ms. Schakowsky votes aye.
6895 Ms. Matsui?
6896 *Ms. Matsui. Aye.
6897 *The Clerk. Ms. Matsui votes aye.
6898 Ms. Castor?
6899 *Ms. Castor. Aye.
6900 *The Clerk. Ms. Castor votes aye.
6901 Mr. Tonko?
6902 *Mr. Tonko. Aye.
6903 *The Clerk. Mr. Tonko votes aye.
6904 Ms. Clarke?
6905 *Ms. Clarke. Aye.
6906 *The Clerk. Ms. Clarke votes aye.
6907 Mr. Ruiz?
6908 *Mr. Ruiz. Aye.
6909 *The Clerk. Mr. Ruiz votes aye.
6910 Mr. Peters?
6911 *Mr. Peters. Aye.
6912 *The Clerk. Mr. Peters votes aye.
6913 Mrs. Dingell?

6914 [No response.]

6915 *The Clerk. Mr. Veasey?

6916 *Mr. Veasey. Aye.

6917 *The Clerk. Mr. Veasey votes aye.

6918 Ms. Kelly?

6919 *Ms. Kelly. Aye.

6920 *The Clerk. Ms. Kelly votes aye.

6921 Ms. Barragan?

6922 *Ms. Barragan. Aye.

6923 *The Clerk. Ms. Barragan votes aye.

6924 Mr. Soto?

6925 *Mr. Soto. Aye.

6926 *The Clerk. Mr. Soto votes aye.

6927 Ms. Schrier?

6928 *Ms. Schrier. Aye.

6929 *The Clerk. Ms. Schrier votes aye.

6930 Mrs. Trahan?

6931 *Mrs. Trahan. Aye.

6932 *The Clerk. Mrs. Trahan votes aye.

6933 Mrs. Fletcher?

6934 [No response.]

6935 *The Clerk. Ms. Ocasio-Cortez?

6936 [No response.]

6937 *The Clerk. Mr. Auchincloss?

6938 *Mr. Auchincloss. Aye.

6939 *The Clerk. Mr. Auchincloss votes aye.
6940 Mr. Carter of Louisiana?
6941 *Mr. Carter of Louisiana. Aye.
6942 *The Clerk. Mr. Carter of Louisiana votes aye.
6943 Mr. Menendez?
6944 *Mr. Menendez. Aye.
6945 *The Clerk. Mr. Menendez votes aye.
6946 Mr. Mullin?
6947 *Mr. Mullin. Aye.
6948 *The Clerk. Mr. Mullin votes aye.
6949 Mr. Landsman?
6950 *Mr. Landsman. Aye.
6951 *The Clerk. Mr. Landsman votes aye.
6952 Ms. McClellan?
6953 *Ms. McClellan. Aye.
6954 *The Clerk. Ms. McClellan votes aye.
6955 Chairman Guthrie?
6956 *The Chair. Aye.
6957 *The Clerk. Chairman Guthrie votes aye.
6958 *The Chair. [Presiding.] Is there anyone seeking
6959 recognition for the purpose -- the gentleman from Texas, Mr.
6960 Crenshaw?
6961 *Mr. Crenshaw. Aye.
6962 *The Clerk. Mr. Crenshaw votes aye.
6963 *The Chair. Crenshaw. Mr. Weber, where is he?

6964 *Mr. Weber. Aye.

6965 *The Clerk. Mr. Weber votes aye.

6966 *The Chair. He is sitting right there.

6967 Mrs. Houchin?

6968 *Mrs. Houchin. Aye.

6969 *The Clerk. Mrs. Houchin votes aye.

6970 *The Chair. Anyone else?

6971 Seeing none, the clerk will report.

6972 [Pause.]

6973 *The Chair. And Mr. Obernolte?

6974 *Mr. Obernolte. Aye.

6975 *The Clerk. Mr. Obernolte votes aye.

6976 *The Chair. Kean, did -- is Mr. Kean recorded? Okay.

6977 [Pause.]

6978 *The Clerk. Mr. Chairman, on that vote there were 48

6979 ayes and 0 noes.

6980 *The Chair. The ayes have it, and the bill is adopted.

6981 The chair calls up H.R. 2004 and asks the clerk to

6982 report.

6983 *The Clerk. H.R. 2004, a bill to direct the Secretary

6984 of Health and Human Services to issue guidance on whether

6985 hospital emergency departments should implement fentanyl

6986 testing as a routine procedure for patients experiencing an

6987 overdose, and for other purposes. Be it enacted by the --

6988 *The Chair. Without objection, the first reading of the

6989 bill is dispensed with, and the bill will be open for
6990 amendment at any point.

6991 So ordered.

6992 [The bill follows:]

6993

6994 *****COMMITTEE INSERT*****

6995

6996 *The Chair. Does anyone seek to be recognized on the
6997 bill?

6998 For what purpose does the gentleman from Ohio seek
6999 recognition?

7000 *Mr. Latta. To speak on the bill, Mr. Chairman.

7001 *The Chair. You are recognized for five minutes to
7002 speak on the bill.

7003 *Mr. Latta. Well, thank you very much, Mr. Chairman.

7004 Currently, many drug screenings that are available in
7005 emergency rooms only test for certain drug classes, and often
7006 do not include synthetic drugs like -- synthetic opioids like
7007 fentanyl. Unfortunately, this turned fatal for 19-year-old
7008 Tyler Shamash. The night before Tyler passed from consuming
7009 fentanyl he was sent to a hospital with a suspected overdose.
7010 The hospital staff conducted the routine drug screening, and
7011 it came back negative. After he passed away, Tyler's family
7012 found that the screening did not detect fentanyl because it
7013 is not a synthetic opioid -- since it is a -- because it is a
7014 synthetic opioid. Had the drug screening detected fentanyl,
7015 he may have been able to receive a higher level of care.

7016 Tyler's Law would require the Department of Health and
7017 Human Services to conduct a study and issue guidance to
7018 hospital emergency rooms on fentanyl testing to ensure that
7019 this will never happen again. I am very proud that this
7020 committee is taking up this legislation.

7021 And I want to thank Tyler's mother, Julie, for all of
7022 her work and her advocacy on behalf of her son, and also for
7023 supporting this legislation. I want to thank Julie for
7024 joining us today in committee.

7025 Mr. Chairman, this is a very important piece of
7026 legislation, and I would ask for the committee to pass the
7027 legislation.

7028 *The Chair. Will the gentleman yield?

7029 *Mr. Latta. And I yield to the chairman.

7030 *The Chair. Thank you for yielding, I appreciate it.

7031 And I know, Ms. Shamash, you flew out here believing
7032 this was going to happen, like, I think July the 1st or 2nd,
7033 all the way from California and back again. And I know we
7034 have several parents here that -- would you mind all standing
7035 and just be recognized with your loved one, your parents or
7036 siblings? So thank you so much for -- thank you for your --

7037 [Applause.]

7038 *The Chair. We are so sorry for your loss, but your
7039 advocacy is a way to prevent other parents and family members
7040 from going through this, and is a testimony to your loved
7041 one. We appreciate you all being here. Thank you.

7042 And I will yield back to the gentleman from Ohio.

7043 *Mr. Latta. Well, thank you, Mr. Chair. And Mr.
7044 Chairman, I yield back the balance of my time.

7045 *The Chair. Thank you. Does anyone seek recognition on

7046 the bill?

7047 Mr. Carter from Louisiana is recognized for five minutes
7048 to speak on the bill.

7049 *Mr. Carter of Louisiana. I move to strike the last
7050 word.

7051 *The Chair. The gentleman is recognized to speak on the
7052 bill.

7053 *Mr. Carter of Louisiana. I would like to speak in
7054 support of H.R. 2004, Tyler's Law, led by Representatives
7055 Lieu and Latta.

7056 In New Orleans we have seen a significant decline in
7057 drug overdoses and overdose-related deaths over the past
7058 year. While these -- while this progress is encouraging, the
7059 fight against opioid epidemic is far from over. We must
7060 continue to invest and expand access to harm reduction
7061 services, evidence-based treatment, and community-based
7062 outreach to ensure that individuals can access the support,
7063 treatment, and resources that are urgently needed. That is
7064 why I am proud to support Tyler's Law, which would take an
7065 actionable step -- steps toward preventing fentanyl overdoses
7066 across the United States, including cities like mine, the
7067 City of New Orleans, and close existing gaps in drug
7068 screening and testing.

7069 Currently, emergency departments do not include fentanyl
7070 in the five-panel toxic drug screening. And because the drug

7071 does not show up on rapid drug testing, it can go largely
7072 undetected. Tyler's Law would close this gap by requiring
7073 HHS to complete a study and examine how often hospitals test
7074 patients experiencing an overdose of fentanyl. Using the
7075 data from the study, HHS would also require -- required to
7076 issue guidance on making fentanyl testing routine procedure
7077 in hospital emergency rooms. This legislation will, in fact,
7078 save lives and fill the existing gaps in the current system.

7079 We offer our most heartfelt condolences, sympathies for
7080 your loss. But know that we hear you, we are working, and we
7081 are sympathetic to make sure nobody else has to die. So God
7082 bless you.

7083 And I urge my colleagues to join me in voting yes.

7084 Mr. Chairman, I yield.

7085 *The Chair. Is there further discussion on the bill? I
7086 heard "Mr. Chairman" from somebody. Oh, you said it. Is
7087 there any further discussion on the bill?

7088 Seeing none, are there any amendments on the bill?

7089 Seeing none, the question -- you have been here for two
7090 times across the country, so now here we are -- the question
7091 now occurs on adopting H.R. 2004. A roll call has been
7092 requested, and the clerk will call the roll.

7093 *The Clerk. Mr. Latta?

7094 *Mr. Latta. Aye.

7095 *The Clerk. Mr. Latta votes aye.

7096 Mr. Griffith?
7097 *Mr. Griffith. Aye.
7098 *The Clerk. Mr. Griffith votes aye.
7099 Mr. Bilirakis?
7100 [No response.]
7101 *The Clerk. Mr. Hudson?
7102 *Mr. Hudson. Aye.
7103 *The Clerk. Mr. Hudson votes aye.
7104 Mr. Carter of Georgia?
7105 *Mr. Carter of Georgia. Aye.
7106 *The Clerk. Mr. Carter of Georgia votes aye.
7107 Mr. Palmer?
7108 *Mr. Palmer. Palmer votes aye.
7109 *The Clerk. Mr. Palmer votes aye.
7110 Mr. Dunn?
7111 [No response.]
7112 *The Clerk. Mr. Crenshaw?
7113 [No response.]
7114 *The Clerk. Mr. Joyce?
7115 [No response.]
7116 *The Clerk. Mr. Weber?
7117 *Mr. Weber. Aye.
7118 *The Clerk. Mr. Weber votes aye.
7119 Mr. Allen?
7120 [No response.]

7121 *The Clerk. Mr. Balderson?
7122 *Mr. Balderson. Aye.
7123 *The Clerk. Mr. Balderson votes aye.
7124 Mr. Fulcher?
7125 *Mr. Fulcher. Fulcher is aye.
7126 *The Clerk. Mr. Fulcher votes aye.
7127 Mr. Pfluger?
7128 [No response.]
7129 *The Clerk. Mrs. Harshbarger?
7130 *Mrs. Harshbarger. Aye.
7131 *The Clerk. Mrs. Harshbarger votes aye.
7132 Mrs. Miller-Meeks?
7133 [No response.]
7134 *The Clerk. Mrs. Cammack?
7135 *Mrs. Cammack. Aye.
7136 *The Clerk. Mrs. Cammack votes aye.
7137 Mr. Obernolte?
7138 *Mr. Obernolte. Aye.
7139 *The Clerk. Mr. Obernolte votes aye.
7140 Mr. James?
7141 *Mr. James. Aye.
7142 *The Clerk. Mr. James votes aye.
7143 Mr. Bentz?
7144 *Mr. Bentz. Aye.
7145 *The Clerk. Mr. Bentz votes aye.

7146 Mrs. Houchin?
7147 *Mrs. Houchin. Aye.
7148 *The Clerk. Mrs. Houchin votes aye.
7149 Mr. Fry?
7150 [No response.]
7151 *The Clerk. Ms. Lee?
7152 *Ms. Lee. Aye.
7153 *The Clerk. Ms. Lee votes aye.
7154 Mr. Langworthy?
7155 *Mr. Langworthy. Aye.
7156 *The Clerk. Mr. Langworthy votes aye.
7157 Mr. Kean?
7158 *Mr. Kean. Aye.
7159 *The Clerk. Mr. Kean votes aye.
7160 Mr. Rulli?
7161 [No response.]
7162 *The Clerk. Mr. Evans?
7163 *Mr. Evans. Aye.
7164 *The Clerk. Mr. Evans votes aye.
7165 Mr. Goldman?
7166 *Mr. Goldman. Aye.
7167 *The Clerk. Mr. Goldman votes aye.
7168 Mrs. Fedorchak?
7169 [No response.]
7170 *The Clerk. Mr. Pallone?

7171 *Mr. Pallone. Aye.
7172 *The Clerk. Mr. Pallone votes aye.
7173 Ms. DeGette?
7174 *Ms. DeGette. Aye.
7175 *The Clerk. Ms. DeGette votes aye.
7176 Ms. Schakowsky?
7177 *Ms. Schakowsky. Aye.
7178 *The Clerk. Ms. Schakowsky votes aye.
7179 Ms. Matsui?
7180 *Ms. Matsui. Aye.
7181 *The Clerk. Ms. Matsui votes aye.
7182 Ms. Castor?
7183 *Ms. Castor. Aye.
7184 *The Clerk. Ms. Castor votes aye.
7185 Mr. Tonko?
7186 *Mr. Tonko. Aye.
7187 *The Clerk. Mr. Tonko votes aye.
7188 Ms. Clarke?
7189 *Ms. Clarke. Aye.
7190 *The Clerk. Ms. Clarke votes aye.
7191 Mr. Ruiz?
7192 *Mr. Ruiz. Aye.
7193 *The Clerk. Mr. Ruiz votes aye.
7194 Mr. Peters?
7195 *Mr. Peters. Aye.

7196 *The Clerk. Mr. Peters votes aye.
7197 Mrs. Dingell?
7198 [No response.]
7199 *The Clerk. Mr. Veasey?
7200 *Mr. Veasey. Aye.
7201 *The Clerk. Mr. Veasey votes aye.
7202 Ms. Kelly?
7203 *Ms. Kelly. Aye.
7204 *The Clerk. Ms. Kelly votes aye.
7205 Ms. Barragan?
7206 *Ms. Barragan. Aye.
7207 *The Clerk. Ms. Barragan votes aye.
7208 Mr. Soto?
7209 *Mr. Soto. Aye.
7210 *The Clerk. Mr. Soto votes aye.
7211 Ms. Schrier?
7212 *Ms. Schrier. Aye.
7213 *The Clerk. Ms. Schrier votes aye.
7214 Mrs. Trahan?
7215 *Mrs. Trahan. Aye.
7216 *The Clerk. Mrs. Trahan votes aye.
7217 Mrs. Fletcher?
7218 *Mrs. Fletcher. Aye.
7219 *The Clerk. Mrs. Fletcher votes aye.
7220 Ms. Ocasio-Cortez?

7221 [No response.]

7222 *The Clerk. Mr. Auchincloss?

7223 *Mr. Auchincloss. Aye.

7224 *The Clerk. Mr. Auchincloss votes aye.

7225 Mr. Carter of Louisiana?

7226 *Mr. Carter of Louisiana. Aye.

7227 *The Clerk. Mr. Carter of Louisiana votes aye.

7228 Mr. Menendez?

7229 *Mr. Menendez. Aye.

7230 *The Clerk. Mr. Menendez votes aye.

7231 Mr. Mullin?

7232 *Mr. Mullin. Aye.

7233 *The Clerk. Mr. Mullin votes aye.

7234 Mr. Landsman?

7235 *Mr. Landsman. Aye.

7236 *The Clerk. Mr. Landsman votes aye.

7237 Ms. McClellan?

7238 *Ms. McClellan. Aye.

7239 *The Clerk. Ms. McClellan votes aye.

7240 Chairman Guthrie?

7241 *The Chair. Aye.

7242 *The Clerk. Chairman Guthrie votes aye.

7243 *The Chair. Is there anyone -- Dr. Miller-Meeks?

7244 *Mrs. Miller-Meeks. Aye.

7245 *The Clerk. Mrs. Miller-Meeks votes aye.

7246 *The Chair. Dr. Joyce?
7247 *Mr. Joyce. Aye.
7248 *The Clerk. Mr. Joyce votes aye.
7249 *The Chair. Dr. Fletcher? Oh, I am sorry. Oh, they
7250 are talking, I am sorry.
7251 Mrs. Fedorchak?
7252 *The Clerk. Mrs. Fedorchak is not recorded.
7253 *Mrs. Fedorchak. Aye.
7254 *The Clerk. Mrs. Fedorchak votes aye.
7255 *The Chair. Mr. Bilirakis?
7256 *The Clerk. Mr. Bilirakis is not recorded.
7257 *Mr. Bilirakis. I vote aye.
7258 *The Clerk. Mr. Bilirakis votes aye.
7259 *The Chair. Is there anyone else seeking to answer the
7260 roll call?
7261 Seeing none, the clerk will report.
7262 [Pause.]
7263 *The Clerk. Mr. Chairman, on that vote there were 46
7264 ayes and 0 noes.
7265 *The Chair. With 46 ayes and 0 noes, the ayes have it
7266 and the bill is adopted.
7267 [Applause.]
7268 *The Chair. Thank you. Thanks for being here. We are
7269 down to just a few tabs, so we are getting close. So thank
7270 you, everyone.

7271 The chair calls up H.R. 7970 and asks the clerk to
7272 report.

7273 *The Clerk. H.R. 7970, a bill to amend the Controlled
7274 Substances Act to permit --

7275 *The Chair. Without objection, the first reading of the
7276 bill is dispensed with, and the bill will be open for
7277 amendment at any point.

7278 So ordered.

7279 [The bill follows:]

7280

7281 *****COMMITTEE INSERT*****

7282

7283 *The Chair. Does anyone seek to be recognized on the
7284 bill?

7285 *Mr. Latta. Mr. Chairman?

7286 *The Chair. For what purpose does the gentleman from
7287 Ohio seek recognition?

7288 *Mr. Latta. To speak on the bill.

7289 *The Chair. You are recognized for five minutes to
7290 speak on the bill.

7291 *Mr. Latta. Well, thank you, Mr. Chairman.

7292 The United States is plagued by fatal overdoses all
7293 across our country driven by the spread of increasingly and
7294 potent synthetic drugs. And one of the -- when we talk about
7295 fatal overdoses, I think it is important to point out that we
7296 had a sheriff that testified before us in committee that
7297 said, you know, these aren't just overdoses, these are
7298 outright poisonings that are occurring out there across our
7299 country.

7300 Nitazenes are a class of illicit synthetic opioids that
7301 have emerged as a growing threat nationwide. Depending on
7302 their chemical composition, some nitazenes can be up to 800
7303 times more potent than morphine and 40 times more potent than
7304 fentanyl, making them among the most dangerous substances
7305 circulating in the illicit drug market today.

7306 Like fentanyl, nitazenes are often mixed with other
7307 drugs without the user's knowledge, significantly increasing

7308 the risk of accidental overdose. Since 2019 nitazenes
7309 related overdoses -- or, as the sheriff said, poisonings --
7310 have contributed to an estimated 2,000 deaths in the United
7311 States, and that number is unfortunately expected to rise as
7312 these substances become more widespread.

7313 Despite their extreme potency, many nitazenes remain
7314 temporarily scheduled, creating enforcement problems for law
7315 enforcement and public health officials. Last year my
7316 colleague and I from Virginia's 9th district and -- we had
7317 the HALT Fentanyl Act which was signed into law after years
7318 of work. This permanently scheduled fentanyl-related
7319 substances as a schedule 1 drug. According to the CDC,
7320 during the timeframe it took from this introduction of the
7321 legislation to when it was signed into law, nearly 195,000
7322 Americans died from synthetic opioid overdoses -- or
7323 poisonings -- driven by illicit fentanyl, with 2025 data
7324 still out.

7325 We cannot sit by and wait for similar numbers to occur
7326 with nitazenes. That is why I am grateful for the committee
7327 taking up this legislation and giving the Federal Government
7328 the tools to stop the poisoning and permanently schedule
7329 nitazene as a schedule 1 drug. And I would ask the committee
7330 to pass this legislation.

7331 And I yield back the balance of my time.

7332 *The Chair. The gentleman yields back. Is anyone

7333 seeking to speak on the bill?

7334 The gentleman from New Jersey is recognized for five
7335 minutes to speak on the bill.

7336 *Mr. Pallone. Mr. Chairman, let me basically say that I
7337 think every member of this committee already agrees that
7338 nitazenes are dangerous. They are potent, and Americans
7339 using it illicitly are suffering and dying. What I am
7340 concerned about is how this bill approaches the problem.

7341 Agencies should be engaging in the process Congress laid
7342 out in the Controlled Substances Act, which requires
7343 scientific and regulatory entities to collaborate on a
7344 science-based approach to drug scheduling. But instead, this
7345 bill would permanently place an entire chemical class, those
7346 that exist today and those not yet invented, into schedule 1,
7347 and it would do so immediately. And I have three problems
7348 with this approach.

7349 First of all, this is structure-based scheduling, not
7350 science-based scheduling. For more than 50 years the CSA has
7351 asked a basic question before a drug enters schedule 1, and
7352 that is, does it actually have a high potential for abuse and
7353 no accepted medical use? And that answer has rested on a
7354 scientific and medical evaluation led by HHS and the FDA.
7355 But H.R. 7970 sets that evaluation aside for an entire class.
7356 Public health experts have warned for years that this rests
7357 on an unproven assumption that structurally similar molecules

7358 behave similarly. They do not always. Scheduling by
7359 structure alone risks sweeping in a potential anecdote
7360 alongside the poison.

7361 Now, second, this bill does not have an off-ramp, and
7362 schedule 1 is where research has stopped. Once a substance
7363 is scheduled, there is no built-in mechanism to remove it if
7364 research later shows it is harmless or even useful, and
7365 schedule 1 is precisely the category that makes that research
7366 hardest to perform. In reviewing the fentanyl class-wide
7367 scheduling order, the Government Accountability Office
7368 documented that scientists faced real obstacles studying
7369 schedule 1 drugs, including long delays in obtaining
7370 approval. And this warning is particularly significant for
7371 nitazene. CDC has found that naloxone can reverse a nitazene
7372 overdose, but often only after repeated doses. So we need a
7373 design -- we need designed better reversal protocols, and
7374 this means studying these compounds: work this bill makes it
7375 harder, not easier.

7376 And third, this approach is not new. DEA already has
7377 the authority to schedule nitazene compounds, and has been
7378 doing so on a temporary basis since 2020. Each time we
7379 schedule one compound, the illicit market answers with
7380 another more potent one. So nitazenes themselves are partly
7381 a product of that dynamic, and the next move in a game of
7382 chemical Whack-a-Mole.

7383 A broad, non-partisan coalition has engaged with
7384 Congress on this repeatedly: the Leadership Conference on
7385 Civil and Human Rights and its 240 member organizations; the
7386 Drug Policy Alliance; the Vera Institute of Justice; the
7387 Sentencing Project; AIDS United; and law enforcement voices
7388 like the Law Enforcement Action Partnership. Their message
7389 is consistent. Permanent class-wide scheduling repeats the
7390 failures of the drug war while diverting resources from what
7391 drove overdose deaths down last year: naloxone, fentanyl
7392 test strips, and medications for opioid use disorder.

7393 So I believe we should schedule what the science directs
7394 us to schedule, build in a research pathway and an off-ramp
7395 for substances later shown to be harmless, and pair any
7396 enforcement with the health investments championed by this
7397 committee. So if we are serious about stopping nitazenes,
7398 let's give scientists the tools to understand them and not
7399 just give prosecutors the tools to charge them.

7400 I urge my colleagues to oppose H.R. 7970, as written,
7401 for all these reasons, and I reserve the balance of my time,
7402 Mr. Chairman.

7403 *The Chair. The gentleman reserves the balance of his
7404 time, or yields the balance?

7405 *Mr. Pallone. I am sorry. Let me yield it because I
7406 don't think anybody wants it.

7407 *The Chair. Okay, thank you. Is anyone seeking

7408 recognition to speak on the bill?

7409 Seeing none, there is an amendment, right?

7410 Does the gentleman -- for what purpose -- are there any
7411 amendments to the bill?

7412 The gentleman from Ohio is recognized.

7413 *Mr. Latta. Well, thank you, Mr. Chairman. I have an
7414 amendment at the desk. File name H7970-FCR-ANS_01.

7415 *The Chair. The clerk will report.

7416 *The Clerk. Amendment in the nature of a substitute to
7417 H.R. 7970.

7418 *The Chair. Without objection, reading of the amendment
7419 is dispensed with.

7420 [The amendment of Mr. Latta follows:]

7421

7422 *****COMMITTEE INSERT*****

7423

7424 *The Chair. And the gentleman from Ohio is recognized
7425 for five minutes in support of the amendment.

7426 *Mr. Latta. Well, thank you, Mr. Chairman. I am not
7427 going to use the five minutes.

7428 It is pretty much -- what this amendment does, it
7429 incorporates the feedback from the Drug Enforcement Agency to
7430 help ensure that this bill will be implemented as intended.
7431 And I am proud of the work that has been done on the bill,
7432 and I encourage my colleagues to support the ANS and the
7433 underlying legislation.

7434 And with that, Mr. Chairman, I am going to yield back
7435 the balance of my time.

7436 *The Chair. The gentleman yields back his time. Is
7437 there any discussion on the amendment?

7438 You have an amendment, right?

7439 So if there is no further discussion on the -- are there
7440 any amendments to the amendment?

7441 The gentlelady from Washington is recognized. Well, for
7442 what purpose does the gentlelady from Washington seek
7443 recognition?

7444 *Ms. Schrier. Mr. Chairman, I have an amendment at the
7445 desk. It is an amendment --

7446 *The Chair. The clerk will --

7447 *Ms. Schrier. Amendment 2.

7448 *The Chair. -- identify the amendment. I am sorry.

7449 *Ms. Schrier. H7970_amendment 2.

7450 *The Chair. The clerk will report.

7451 *The Clerk. Amendment to the amendment in the nature of
7452 a substitute to H.R. 7970.

7453 *The Chair. Without objection, the reading of the
7454 amendment is dispensed with.

7455 [The amendment of Ms. Schrier follows:]

7456

7457 *****COMMITTEE INSERT*****

7458

7459 *The Chair. And the gentlelady is recognized for five
7460 minutes in support of her amendment.

7461 *Ms. Schrier. Thank you, Mr. Chairman. I am really
7462 glad to see the committee advance this important bill to
7463 permanently control nitazenes as a schedule 1 drug.

7464 As a physician, I am extremely concerned about how
7465 dangerous nitazenes are. These drugs are nearly 500 times
7466 more potent than morphine, and they are incredibly deadly and
7467 risky. And the opioid epidemic, particularly with fentanyl,
7468 has already devastated far too many families in my State of
7469 Washington and across the country. And we just can't let
7470 another dangerous synthetic drug take any more lives.

7471 But at the same time, we have to be really smart about
7472 how we tackle this crisis. Right now burdensome restrictions
7473 on schedule 1 drugs have made it incredibly difficult for
7474 scientists to study them. This hurts our ability to learn
7475 more about the risks and potential medical benefits of these
7476 substances. Maybe there are some. It even impairs our
7477 ability to learn about how to treat overdoses, and we need to
7478 know that. So, for example, we wouldn't have naloxone, the
7479 medication that is used to reverse an opioid overdose, if
7480 research hadn't been done on Oxymorphone, which is derived
7481 from morphine, a schedule 2 drug.

7482 That is why it is important that we lower the barriers
7483 to conducting valuable research on schedule 1 drugs. I

7484 supported these research reforms for schedule 1 drugs in the
7485 HALT Fentanyl Act, which was signed into law last year.
7486 However, the Trump Administration has been dragging their
7487 feet. They were supposed to issue guidelines to implement
7488 this bill and to ease a path to doing this research nearly
7489 six months ago, and we have not seen a final rule. And this
7490 research is really important.

7491 We shouldn't keep passing new laws while Federal
7492 agencies ignore the ones we already have on the books, so I
7493 am introducing this amendment to ensure guidance on HALT
7494 Fentanyl implementation has been issued before any part of
7495 Stop Nitazenes can take effect. I would encourage everyone
7496 to vote yes.

7497 And I yield back. Thank you.

7498 *The Chair. The gentlelady yields back. Is there any
7499 discussion of the amendment?

7500 For what purpose -- the gentleman from Texas is
7501 recognized to speak on the amendment.

7502 *Mr. Goldman. I move to strike the last word.

7503 *The Chair. The gentleman is recognized to speak on the
7504 amendment.

7505 *Mr. Goldman. Thank you, Mr. Chairman. I strongly
7506 oppose this amendment to H.R. 7970, the Stop Nitazene Act.

7507 While I am in opposition to this amendment, I want to
7508 take a moment to thank my colleague for highlighting the good

7509 work we have accomplished in the HALT Fentanyl Act, which
7510 included streamlining the processes for researching schedule
7511 1 controlled substances.

7512 The rulemaking provision in question was in regards to
7513 implementation and enactment of the HALT Fentanyl research
7514 reforms. The committee has been in communication with DEA,
7515 and I can confirm that DEA is actively working on
7516 implementing this law, as well as implementing the policy
7517 regulations. DEA has already registered over 100 researchers
7518 since HALT Fentanyl went into effect, and they are doing so
7519 even faster than the 30-day deadline for researchers with
7520 existing registrations and the 45-day deadline for new
7521 researchers as required by HALT. The DEA's average time to
7522 register researchers is 19 days. The Stop Nitazene Act will
7523 not harm the ability to conduct research on nitazenes. The
7524 Stop Nitazenes Act makes our community safer and prevent
7525 undue harm to the American people, and that is not something
7526 we should delay.

7527 I strongly urge my colleagues to vote no on this
7528 amendment.

7529 I thank the chair and I yield back.

7530 *The Chair. Thank you. The gentleman yields back. Is
7531 there further discussion on the amendment?

7532 Seeing none, the -- if there is no further discussion,
7533 the vote occurs on the amendment.

7534 All those in favor shall signify by saying aye.

7535 All those opposed, say nay.

7536 In the opinion of the chair the nays have it.

7537 Is there any further amendments to the amendment?

7538 Seeing none, if there is no further discussion, the vote
7539 occurs on adopting the amendment in the nature of a
7540 substitute.

7541 All those in favor shall signify by saying aye.

7542 All those opposed, nay.

7543 In the opinion of the chair the ayes have it, and the
7544 amendment is agreed to.

7545 Are there any further amendments?

7546 Seeing none, the question now occurs on adopting H.R.
7547 7970, as amended. A roll call has been requested, and the
7548 clerk will call the roll.

7549 *The Clerk. Mr. Latta?

7550 *Mr. Latta. Aye.

7551 *The Clerk. Mr. Latta votes aye.

7552 Mr. Griffith?

7553 *Mr. Griffith. Aye.

7554 *The Clerk. Mr. Griffith votes aye.

7555 Mr. Bilirakis?

7556 *Mr. Bilirakis. Aye.

7557 *The Clerk. Mr. Bilirakis votes aye.

7558 Mr. Hudson?

7559 *Mr. Hudson. Aye.
7560 *The Clerk. Mr. Hudson votes aye.
7561 Mr. Carter of Georgia?
7562 *Mr. Carter of Georgia. Aye.
7563 *The Clerk. Mr. Carter of Georgia votes aye.
7564 Mr. Palmer?
7565 [No response.]
7566 *The Clerk. Mr. Palmer?
7567 *Mr. Palmer. Palmer votes aye.
7568 *The Clerk. Mr. Palmer votes aye.
7569 Mr. Dunn?
7570 [No response.]
7571 *The Clerk. Mr. Crenshaw?
7572 [No response.]
7573 *The Clerk. Mr. Joyce?
7574 *Mr. Joyce. Aye.
7575 *The Clerk. Mr. Joyce votes aye.
7576 Mr. Weber?
7577 *Mr. Weber. Aye.
7578 *The Clerk. Mr. Weber votes aye.
7579 Mr. Allen?
7580 [No response.]
7581 *The Clerk. Mr. Balderson?
7582 *Mr. Balderson. Aye.
7583 *The Clerk. Mr. Balderson votes aye.

7584 Mr. Fulcher?
7585 *Mr. Fulcher. Fulcher is aye.
7586 *The Clerk. Mr. Fulcher votes aye.
7587 Mr. Pfluger?
7588 [No response.]
7589 *The Clerk. Mrs. Harshbarger?
7590 *Mrs. Harshbarger. Aye.
7591 *The Clerk. Mrs. Harshbarger votes aye.
7592 Mrs. Miller-Meeks?
7593 [No response.]
7594 *The Clerk. Mrs. Cammack?
7595 *Mrs. Cammack. Aye.
7596 *The Clerk. Mrs. Cammack votes aye.
7597 Mr. Obernolte?
7598 *Mr. Obernolte. Aye.
7599 *The Clerk. Mr. Obernolte votes aye.
7600 Mr. James?
7601 *Mr. James. Aye.
7602 *The Clerk. Mr. James votes aye.
7603 Mr. Bentz?
7604 *Mr. Bentz. Aye.
7605 *The Clerk. Mr. Bentz votes aye.
7606 Mrs. Houchin?
7607 *Mrs. Houchin. Aye.
7608 *The Clerk. Mrs. Houchin votes aye.

7609 Mr. Fry?
7610 [No response.]
7611 *The Clerk. Ms. Lee?
7612 *Ms. Lee. Aye.
7613 *The Clerk. Ms. Lee votes aye.
7614 Mr. Langworthy?
7615 *Mr. Langworthy. Aye.
7616 *The Clerk. Mr. Langworthy votes aye.
7617 Mr. Kean?
7618 *Mr. Kean. Aye.
7619 *The Clerk. Mr. Kean votes aye.
7620 Mr. Rulli?
7621 [No response.]
7622 *The Clerk. Mr. Evans?
7623 *Mr. Evans. Aye.
7624 *The Clerk. Mr. Evans votes aye.
7625 Mr. Goldman?
7626 *Mr. Goldman. Aye.
7627 *The Clerk. Mr. Goldman votes aye.
7628 Mrs. Fedorchak?
7629 *Mrs. Fedorchak. Aye.
7630 *The Clerk. Mrs. Fedorchak votes aye.
7631 Mr. Pallone?
7632 *Mr. Pallone. No.
7633 *The Clerk. Mr. Pallone votes no.

7634 Ms. DeGette?

7635 *Ms. DeGette. No.

7636 *The Clerk. Ms. DeGette votes no.

7637 Ms. Schakowsky?

7638 *Ms. Schakowsky. No, no.

7639 *The Clerk. Ms. Schakowsky votes no.

7640 Ms. Matsui?

7641 *Ms. Matsui. No.

7642 *The Clerk. Ms. Matsui votes no.

7643 Ms. Castor?

7644 *Ms. Castor. No.

7645 *The Clerk. Ms. Castor votes no.

7646 Mr. Tonko?

7647 *Mr. Tonko. No.

7648 *The Clerk. Mr. Tonko votes no.

7649 Ms. Clarke?

7650 *Ms. Clarke. No.

7651 *The Clerk. Ms. Clarke votes no.

7652 Mr. Ruiz?

7653 *Mr. Ruiz. No.

7654 *The Clerk. Mr. Ruiz votes no.

7655 Mr. Peters?

7656 *Mr. Peters. No.

7657 *The Clerk. Mr. Peters votes no.

7658 Mrs. Dingell?

7659 [No response.]

7660 *The Clerk. Mr. Veasey?

7661 *Mr. Veasey. No.

7662 *The Clerk. Mr. Veasey votes no.

7663 Ms. Kelly?

7664 *Ms. Kelly. No.

7665 *The Clerk. Ms. Kelly votes no.

7666 Ms. Barragan?

7667 *Ms. Barragan. No.

7668 *The Clerk. Ms. Barragan votes no.

7669 Mr. Soto?

7670 *Mr. Soto. No.

7671 *The Clerk. Mr. Soto votes no.

7672 Ms. Schrier?

7673 *Ms. Schrier. Aye.

7674 *The Clerk. Ms. Schrier votes aye.

7675 Mrs. Trahan?

7676 *Mrs. Trahan. No.

7677 *The Clerk. Mrs. Trahan votes no.

7678 Mrs. Fletcher?

7679 [No response.]

7680 *The Clerk. Mrs. Fletcher?

7681 *Mrs. Fletcher. Fletcher? No.

7682 *The Clerk. Mrs. Fletcher votes no.

7683 Ms. Ocasio-Cortez?

7684 [No response.]

7685 *The Clerk. Mr. Auchincloss?

7686 *Mr. Auchincloss. No.

7687 *The Clerk. Mr. Auchincloss votes no.

7688 Mr. Carter of Louisiana?

7689 *Mr. Carter of Louisiana. No.

7690 *The Clerk. Mr. Carter of Louisiana votes no.

7691 Mr. Menendez?

7692 *Mr. Menendez. No.

7693 *The Clerk. Mr. Menendez votes no.

7694 Mr. Mullin?

7695 *Mr. Mullin. No.

7696 *The Clerk. Mr. Mullin votes no.

7697 Mr. Landsman?

7698 *Mr. Landsman. No.

7699 *The Clerk. Mr. Landsman votes no.

7700 Ms. McClellan?

7701 *Ms. McClellan. No.

7702 *The Clerk. Ms. McClellan votes no.

7703 Chairman Guthrie?

7704 *The Chair. Aye.

7705 *The Clerk. Chairman Guthrie votes aye.

7706 *The Chair. Mr. Pfluger?

7707 *Mr. Pfluger. Aye.

7708 *The Clerk. Mr. Pfluger votes aye.

7709 *The Chair. Mr. Allen?
7710 *Mr. Allen. Allen votes aye.
7711 *The Clerk. Mr. Allen votes aye.
7712 *The Chair. Mr. Rulli?
7713 *Mr. Rulli. Rulli votes aye.
7714 *The Clerk. Mr. Rulli votes aye.
7715 *The Chair. Anyone on your side?
7716 The clerk will report.
7717 [Pause.]
7718 *Mrs. Miller-Meeks. How is Miller-Meeks recorded?
7719 *The Chair. Mrs. Miller-Meeks is -- you haven't called
7720 the roll yet.
7721 Dr. Miller-Meeks?
7722 *Mrs. Miller-Meeks. Aye.
7723 *The Chair. Mrs. Miller-Meeks votes aye.
7724 [Pause.]
7725 *The Clerk. Mr. Chairman, on that vote there were 28
7726 ayes and 21 noes.
7727 *The Chair. The ayes have it. The bill is adopted.
7728 So the chair calls up H.R. 1561 and asks the clerk to
7729 report.
7730 *The Clerk. H.R. 1561, a bill to require research --
7731 *The Chair. Without objection, the first reading of the
7732 bill is dispensed with, and the bill will be up for amendment
7733 at any point.

7734 So ordered.

7735 [The bill follows:]

7736

7737 *****COMMITTEE INSERT*****

7738

7739 *The Chair. Does anyone seek to be recognized on the
7740 bill?

7741 The gentleman from New Jersey is recognized to speak on
7742 the bill.

7743 *Mr. Pallone. Thank you. The Alert Communities Act
7744 will improve first responders' capacity for responding to
7745 overdoses by allowing training grants to be used to
7746 facilitate access to fentanyl and Xylazine test strips.

7747 In the past decade there has been a rapid increase in
7748 the proliferation of fentanyl and xylazine within the illicit
7749 drug supply. They are being added to many drugs to make them
7750 more powerful and addictive, and both fentanyl and xylazine
7751 are associated with an increase in overdose risk. And too
7752 often people who are exposed to it are unaware that it has
7753 been added to their drugs. However, there are steps that can
7754 be taken to determine whether drugs contain fentanyl and
7755 Xylazine, including using test strips, and this drug-checking
7756 technology is inexpensive and easy to use, and it can reduce
7757 the potential risks associated with substance use.

7758 With an ever-changing drug landscape and increasingly
7759 contaminated drug supply, it is important that we continue to
7760 support harm reduction strategies like test strips. And I am
7761 glad that this bill expands access to test strips by training
7762 first responders on their use and allowing them to distribute
7763 test strips as appropriate.

7764 I am grateful to my colleague, Representative Crockett,
7765 and others for their work on this bill, and I strongly urge
7766 my colleagues to join me in supporting the bill.

7767 I yield back. Thank you, Mr. Chairman.

7768 *The Chair. Thank you. The gentleman yields back. Is
7769 there further discussion on the bill?

7770 Seeing none, are there any amendments to the bill?

7771 Seeing none, we will call this roll. We have got two
7772 more roll calls after this that appear, unless there is
7773 amendments. But two more, so we are getting close.

7774 So anyway, the question now occurs on adopting H.R.
7775 1561. A roll call has been requested, and the clerk will
7776 call the roll.

7777 *The Clerk. Mr. Latta?

7778 *Mr. Latta. Aye.

7779 *The Clerk. Mr. Latta votes aye.

7780 Mr. Griffith?

7781 [No response.]

7782 *The Clerk. Mr. Bilirakis?

7783 *Mr. Bilirakis. Aye.

7784 *The Clerk. Mr. Bilirakis votes aye.

7785 Mr. Hudson?

7786 *Mr. Hudson. Aye.

7787 *The Clerk. Mr. Hudson votes aye.

7788 Mr. Carter of Georgia?

7789 [No response.]
7790 *The Clerk. Mr. Palmer?
7791 [No response.]
7792 *The Clerk. Mr. Dunn?
7793 [No response.]
7794 *The Clerk. Mr. Crenshaw?
7795 [No response.]
7796 *The Clerk. Mr. Joyce?
7797 *Mr. Joyce. Aye.
7798 *The Clerk. Mr. Joyce votes aye.
7799 Mr. Weber?
7800 *Mr. Weber. Aye.
7801 *The Clerk. Mr. Weber votes aye.
7802 Mr. Allen?
7803 *Mr. Allen. Aye.
7804 *The Clerk. Mr. Allen votes aye.
7805 Mr. Balderson?
7806 *Mr. Balderson. Aye.
7807 *The Clerk. Mr. Balderson votes aye.
7808 Mr. Fulcher?
7809 *Mr. Fulcher. Fulcher is aye.
7810 *The Clerk. Mr. Fulcher votes aye.
7811 Mr. Pfluger?
7812 *Mr. Pfluger. Aye.
7813 *The Clerk. Mr. Pfluger votes aye.

7814 Mrs. Harshbarger?
7815 *Mrs. Harshbarger. Aye.
7816 *The Clerk. Mrs. Harshbarger votes aye.
7817 Mrs. Miller-Meeks?
7818 [No response.]
7819 *The Clerk. Mrs. Cammack?
7820 *Mrs. Cammack. Aye.
7821 *The Clerk. Mrs. Cammack votes aye.
7822 Mr. Obernolte?
7823 *Mr. Obernolte. Aye.
7824 *The Clerk. Mr. Obernolte votes aye.
7825 Mr. James?
7826 *Mr. James. Aye.
7827 *The Clerk. Mr. James votes aye.
7828 Mr. Bentz?
7829 [No response.]
7830 *The Clerk. Mrs. Houchin?
7831 *Mrs. Houchin. Aye.
7832 *The Clerk. Mrs. Houchin votes aye.
7833 Mr. Fry?
7834 [No response.]
7835 *The Clerk. Ms. Lee?
7836 *Ms. Lee. Aye.
7837 *The Clerk. Ms. Lee votes aye.
7838 Mr. Langworthy?

7839 *Mr. Langworthy. Aye.
7840 *The Clerk. Mr. Langworthy votes aye.
7841 Mr. Kean?
7842 [No response.]
7843 *The Clerk. Mr. Rulli?
7844 *Mr. Rulli. Aye.
7845 *The Clerk. Mr. Rulli votes aye.
7846 Mr. Evans?
7847 *Mr. Evans. Aye.
7848 *The Clerk. Mr. Evans votes aye.
7849 Mr. Goldman?
7850 *Mr. Goldman. Aye.
7851 *The Clerk. Mr. Goldman votes aye.
7852 Mrs. Fedorchak?
7853 *Mrs. Fedorchak. Aye.
7854 *The Clerk. Mrs. Fedorchak votes aye.
7855 Mr. Pallone?
7856 [No response.]
7857 *The Clerk. Ms. DeGette?
7858 *Ms. DeGette. Aye.
7859 *The Clerk. Ms. DeGette votes aye.
7860 Ms. Schakowsky?
7861 *Ms. Schakowsky. Aye.
7862 *The Clerk. Ms. Schakowsky votes aye.
7863 Ms. Matsui?

7864 *Ms. Matsui. Aye.
7865 *The Clerk. Ms. Matsui votes aye.
7866 Ms. Castor?
7867 *Ms. Castor. Aye.
7868 *The Clerk. Ms. Castor votes aye.
7869 Mr. Tonko?
7870 *Mr. Tonko. Aye.
7871 *The Clerk. Mr. Tonko votes aye.
7872 Ms. Clarke?
7873 *Ms. Clarke. Aye.
7874 *The Clerk. Ms. Clarke votes aye.
7875 Mr. Ruiz?
7876 *Mr. Ruiz. Aye.
7877 *The Clerk. Mr. Ruiz votes aye.
7878 Mr. Peters?
7879 *Mr. Peters. Aye.
7880 *The Clerk. Mr. Peters votes aye.
7881 Mrs. Dingell?
7882 [No response.]
7883 *The Clerk. Mr. Veasey?
7884 [No response.]
7885 *The Clerk. Mr. Veasey?
7886 *Mr. Veasey. Yes.
7887 *The Clerk. Mr. Veasey votes aye.
7888 Ms. Kelly?

7889 *Ms. Kelly. Aye.
7890 *The Clerk. Ms. Kelly votes aye.
7891 Ms. Barragan?
7892 *Ms. Barragan. Aye.
7893 *The Clerk. Ms. Barragan votes aye.
7894 Mr. Soto?
7895 *Mr. Soto. Aye.
7896 *The Clerk. Mr. Soto votes aye.
7897 Ms. Schrier?
7898 *Ms. Schrier. Aye.
7899 *The Clerk. Ms. Schrier votes aye.
7900 Mrs. Trahan?
7901 *Mrs. Trahan. Aye.
7902 *The Clerk. Mrs. Trahan votes aye.
7903 Mrs. Fletcher?
7904 *Mrs. Fletcher. Aye.
7905 *The Clerk. Mrs. Fletcher votes aye.
7906 Ms. Ocasio-Cortez?
7907 *Ms. Ocasio-Cortez. Aye.
7908 *The Clerk. Ms. Ocasio-Cortez votes aye.
7909 Mr. Auchincloss?
7910 *Mr. Auchincloss. Aye.
7911 *The Clerk. Mr. Auchincloss votes aye.
7912 Mr. Carter of Louisiana?
7913 *Mr. Carter of Louisiana. Aye.

7914 *The Clerk. Mr. Carter of Louisiana votes aye.
7915 Mr. Menendez?
7916 *Mr. Menendez. Aye.
7917 *The Clerk. Mr. Menendez votes aye.
7918 Mr. Mullin?
7919 *Mr. Mullin. Aye.
7920 *The Clerk. Mr. Mullin votes aye.
7921 Mr. Landsman?
7922 *Mr. Landsman. Aye.
7923 *The Clerk. Mr. Landsman votes aye.
7924 Ms. McClellan?
7925 *Ms. McClellan. Aye.
7926 *The Clerk. Ms. McClellan votes aye.
7927 Chairman Guthrie?
7928 *The Chair. Aye.
7929 *The Clerk. Chairman Guthrie votes aye.
7930 *The Chair. Mr. Palmer?
7931 *The Clerk. Mr. Palmer is not recorded.
7932 *Mr. Palmer. Palmer votes aye.
7933 *The Clerk. Mr. Palmer votes aye.
7934 *The Chair. Mr. Griffith?
7935 *Mr. Griffith. Aye.
7936 *The Clerk. Mr. Griffith votes aye.
7937 *The Chair. Mr. Pallone?
7938 *Mr. Pallone. Votes aye.

7939 *The Clerk. Mr. Pallone votes aye.

7940 *The Chair. Is anyone seeking to answer the roll?

7941 Seeing none, the clerk will report.

7942 [Pause.]

7943 *The Clerk. Mr. Chairman, on that --

7944 *The Chair. The gentleman -- how is Mr. Crenshaw
7945 recorded?

7946 *The Clerk. Mr. Crenshaw is not recorded.

7947 *Mr. Crenshaw. Yes.

7948 *The Clerk. Mr. Crenshaw votes aye.

7949 *The Chair. Mr. Carter -- and Mr. Carter.

7950 *The Clerk. Mr. Carter of Georgia is not recorded.

7951 *Mr. Carter of Georgia. Aye.

7952 *The Clerk. Mr. Carter votes aye.

7953 *The Chair. Yes, the gentlelady from New York, is she
7954 here? Did you get your recorded?

7955 *Ms. Ocasio-Cortez. Yes.

7956 *The Chair. Okay, so the gentlelady is recorded.

7957 All right, so the clerk will report.

7958 *The Clerk. Mr. Chairman, on that vote there were 48
7959 ayes and 0 noes.

7960 *The Chair. The ayes have it, and the bill is agreed
7961 to. So two more votes -- should be two more votes for
7962 everyone, so thank you.

7963 So the chair calls up H.R. 7994 and asks the clerk to

7964 report.

7965 *The Clerk. H.R. 7994, a bill to establish --

7966 *The Chair. Without objection, the first reading of the
7967 bill is dispensed with. The bill will be open for amendment
7968 at any point.

7969 So ordered.

7970 [The bill follows:]

7971

7972 *****COMMITTEE INSERT*****

7973

7974 *The Chair. Does anyone seek to be recognized on the
7975 bill?

7976 For what purpose does the gentleman from California seek
7977 recognition?

7978 *Mr. Ruiz. Mr. Chairman, I have an amendment in the
7979 nature of a substitute at the desk under the file name HR --

7980 *The Chair. Does anyone want to speak on the bill? If
7981 -- we could speak to the amendment, as well.

7982 So if no one will speak on the bill, so the gentleman's
7983 amendment, if you will report.

7984 *The Clerk. Amendment in the nature of a substitute to
7985 H.R. 7994.

7986 *The Chair. Without objection, the reading of the
7987 amendment is dispensed with.

7988 [The amendment of Mr. Ruiz follows:]

7989

7990 *****COMMITTEE INSERT*****

7991

7992 *The Chair. And the gentleman is recognized for five
7993 minutes to speak on the amendment.

7994 *Mr. Ruiz. Thank you, Mr. Chairman.

7995 H.R. 7994, the Helping Educators Respond to Overdoses
7996 Act, or the HERO Act, is practical legislation that will save
7997 kids' lives. This bipartisan bill that I lead with my
7998 colleague, Representative Bilirakis, also known in Greece as
7999 Zeus himself, as how popular he is, establishes a grant
8000 program for schools to purchase opioid overdose reversal
8001 drugs, making these lifesaving medications accessible in
8002 schools in case, God forbid, a student needs them.

8003 It also establishes grants to provide critical training
8004 for staff and implement educational resources for students
8005 and communities to help combat the opioid epidemic.

8006 The bill also includes transparency measures that
8007 require schools to report when these opioid reversal
8008 medications are administered.

8009 This amendment in the nature of a substitute streamlines
8010 this reporting requirement to be less burdensome for schools
8011 while maintaining the bill's original intent.

8012 The opioid epidemic is a public health crisis, and we
8013 need to take action. According to UCLA Health, an average of
8014 22 adolescents ages 14 to 18 died every week in the U.S. in
8015 2022 from drug overdoses, the equivalent of a full high
8016 school classroom each week, bringing the death rate to 5.2

8017 per 100,000.

8018 As an emergency physician, I have cared for many
8019 patients overdosing on opioids. I have also had to comfort
8020 family members of patients who, unfortunately, were not able
8021 to receive lifesaving Narcan in time, and died. And let me
8022 tell you, it is such a tragedy and so heartbreaking to know
8023 that a patient could have survived if they had lifesaving
8024 Narcan available. Every story that ends in an overdose is
8025 tragic, but it cuts that much deeper when it could have been
8026 prevented had Narcan been administered.

8027 So we need to take action now to mitigate overdoses
8028 through training, through education, and through awareness,
8029 and we need to ensure widespread access to opioid overdose
8030 reversal medications like naloxone or Narcan. These
8031 medications exist, but they only work if they are accessible.

8032 This bill is a pragmatic, actionable step we can take to
8033 tackle the opioid crisis head on, and our kids' lives depend
8034 on that. So I urge my colleagues to support and move this
8035 bill in a bipartisan manner.

8036 Thank you, and I yield.

8037 *The Chair. Thank you. The gentleman yields back. Is
8038 there a discussion on the amendment in the nature of a
8039 substitute?

8040 The gentleman from Florida is recognized for five
8041 minutes to speak on the amendment.

8042 *Mr. Ruiz. Zeus.

8043 *Mr. Bilirakis. Thank you, Mr. Chairman and, you know
8044 what? I have been called a heck of a lot worse, so I will
8045 accept it graciously. Thank you very much. So, in any case
8046 I -- let's get on to this very serious bill.

8047 I support the bill, obviously, and I want to speak in
8048 support of the amendment of the underlying bill sponsored by
8049 my good friend, Dr. Ruiz. And again, it is just an honor to
8050 do this because I know what it means to these families. We
8051 have got to get this across the finish line as soon as
8052 possible.

8053 Communities across the country continue to feel the
8054 devastating impact of the opioid epidemic, and schools should
8055 be equipped to respond when an overdose emergency occurs.
8056 This legislation provides targeted support to help schools
8057 obtain opioid overdose reversal drugs, develop emergency
8058 response plans, and provide education on overdose response
8059 and prevention. These are practical steps that will help
8060 schools protect students and save lives, and this is why we
8061 are here and why we ran for office, to make a real
8062 difference, a direct impact on people's lives. So we are
8063 here to save lives.

8064 And I appreciate the cosponsor, Dr. Ruiz, in working
8065 with me on these very, very important bills. I want to thank
8066 him and -- for his partnership and leadership on this

8067 important piece of legislation. And I urge my colleagues to
8068 support the amendment and the underlying bill.

8069 And I yield back.

8070 *The Chair. Thank you. The gentleman yields back. Is
8071 there further discussion of the amendment?

8072 Seeing none, the question occurs on adoption of the
8073 amendment.

8074 All those in favor shall signify by saying aye.

8075 All those opposed, nay.

8076 The ayes have it. The amendment is agreed to. Are
8077 there any further amendments?

8078 Seeing none, the question -- we do have one more bill
8079 after this -- so the question now occurs on adopting H.R.
8080 7994, as amended. A roll call has been requested, and the
8081 clerk will call the roll.

8082 *The Clerk. Mr. Latta?

8083 *Mr. Latta. Aye.

8084 *The Clerk. Mr. Latta votes aye.

8085 Mr. Griffith?

8086 *Mr. Griffith. Aye.

8087 *The Clerk. Mr. Griffith votes aye.

8088 Mr. Bilirakis?

8089 [No response.]

8090 *The Clerk. Mr. Bilirakis?

8091 [Laughter.]

8092 *Voice. Even Zeus has to vote.
8093 *Mr. Bilirakis. Aye.
8094 *The Clerk. Mr. Bilirakis votes aye.
8095 Mr. Hudson?
8096 *Mr. Hudson. Aye.
8097 *The Clerk. Mr. Hudson votes aye.
8098 Mr. Carter of Georgia?
8099 *Mr. Carter of Georgia. Aye.
8100 *The Clerk. Mr. Carter of Georgia votes aye.
8101 Mr. Palmer?
8102 *Mr. Palmer. Aye.
8103 *The Clerk. Mr. Palmer votes aye.
8104 Mr. Dunn?
8105 [No response.]
8106 *The Clerk. Mr. Crenshaw?
8107 [No response.]
8108 *The Clerk. Mr. Joyce?
8109 *Mr. Joyce. Aye.
8110 *The Clerk. Mr. Joyce votes aye.
8111 Mr. Weber?
8112 *Mr. Weber. Aye.
8113 *The Clerk. Mr. Weber votes aye.
8114 Mr. Allen?
8115 *Mr. Allen. Aye.
8116 *The Clerk. Mr. Allen votes aye.

8117 Mr. Balderson?
8118 *Mr. Balderson. Aye.
8119 *The Clerk. Mr. Balderson votes aye.
8120 Mr. Fulcher?
8121 *Mr. Fulcher. Fulcher is aye.
8122 *The Clerk. Mr. Fulcher votes aye.
8123 Mr. Pfluger?
8124 *Mr. Pfluger. Aye.
8125 *The Clerk. Mr. Pfluger votes aye.
8126 Mrs. Harshbarger?
8127 *Mrs. Harshbarger. Aye.
8128 *The Clerk. Mrs. Harshbarger votes aye.
8129 Mrs. Miller-Meeks?
8130 [No response.]
8131 *The Clerk. Mrs. Cammack?
8132 *Mrs. Cammack. Aye.
8133 *The Clerk. Mrs. Cammack votes aye.
8134 Mr. Obernolte?
8135 *Mr. Obernolte. Aye.
8136 *The Clerk. Mr. Obernolte votes aye.
8137 Mr. James?
8138 *Mr. James. Aye.
8139 *The Clerk. Mr. James votes aye.
8140 Mr. Bentz?
8141 [No response.]

8142 *The Clerk. Mrs. Houchin?
8143 *Mrs. Houchin. Aye.
8144 *The Clerk. Mrs. Houchin votes aye.
8145 Mr. Fry?
8146 [No response.]
8147 *The Clerk. Ms. Lee?
8148 *Ms. Lee. Aye.
8149 *The Clerk. Ms. Lee votes aye.
8150 Mr. Langworthy?
8151 *Mr. Langworthy. Aye.
8152 *The Clerk. Mr. Langworthy votes aye.
8153 Mr. Kean?
8154 [No response.]
8155 *The Clerk. Mr. Rulli?
8156 *Mr. Rulli. Aye.
8157 *The Clerk. Mr. Rulli votes aye.
8158 Mr. Evans?
8159 *Mr. Evans. Aye.
8160 *The Clerk. Mr. Evans votes aye.
8161 Mr. Goldman?
8162 *Mr. Goldman. Aye.
8163 *The Clerk. Mr. Goldman votes aye.
8164 Mrs. Fedorchak?
8165 *Mrs. Fedorchak. Aye.
8166 *The Clerk. Mrs. Fedorchak votes aye.

8167 Mr. Pallone?
8168 *Mr. Pallone. Aye.
8169 *The Clerk. Mr. Pallone votes aye.
8170 Ms. DeGette?
8171 *Ms. DeGette. Aye.
8172 *The Clerk. Ms. DeGette votes aye.
8173 Ms. Schakowsky?
8174 *Ms. Schakowsky. Aye.
8175 *The Clerk. Ms. Schakowsky votes aye.
8176 Ms. Matsui?
8177 *Ms. Matsui. Aye.
8178 *The Clerk. Ms. Matsui votes aye.
8179 Ms. Castor?
8180 *Ms. Castor. Aye.
8181 *The Clerk. Ms. Castor votes aye.
8182 Mr. Tonko?
8183 *Mr. Tonko. Aye.
8184 *The Clerk. Mr. Tonko votes aye.
8185 Ms. Clarke?
8186 *Ms. Clarke. Aye.
8187 *The Clerk. Ms. Clarke votes aye.
8188 Mr. Ruiz?
8189 *Mr. Ruiz. Aye.
8190 *The Clerk. Mr. Ruiz votes aye.
8191 Mr. Peters?

8192 *Mr. Peters. Aye.
8193 *The Clerk. Mr. Peters votes aye.
8194 Mrs. Dingell?
8195 [No response.]
8196 *The Clerk. Mr. Veasey?
8197 *Mr. Veasey. Aye.
8198 *The Clerk. Mr. Veasey votes aye.
8199 Ms. Kelly?
8200 *Ms. Kelly. Aye.
8201 *The Clerk. Ms. Kelly votes aye.
8202 Ms. Barragan?
8203 *Ms. Barragan. Aye.
8204 *The Clerk. Ms. Barragan votes aye.
8205 Mr. Soto?
8206 *Mr. Soto. Aye.
8207 *The Clerk. Mr. Soto votes aye.
8208 Ms. Schrier?
8209 *Ms. Schrier. Aye.
8210 *The Clerk. Ms. Schrier votes aye.
8211 Mrs. Trahan?
8212 *Mrs. Trahan. Aye.
8213 *The Clerk. Mrs. Trahan votes aye.
8214 Mrs. Fletcher?
8215 *Mrs. Fletcher. Aye.
8216 *The Clerk. Mrs. Fletcher votes aye.

8217 Ms. Ocasio-Cortez?

8218 *Ms. Ocasio-Cortez. Aye.

8219 *The Clerk. Ms. Ocasio-Cortez votes aye.

8220 Mr. Auchincloss?

8221 *Mr. Auchincloss. Aye.

8222 *The Clerk. Mr. Auchincloss votes aye.

8223 Mr. Carter of Louisiana?

8224 *Mr. Carter of Louisiana. Aye.

8225 *The Clerk. Mr. Carter of Louisiana votes aye.

8226 Mr. Menendez?

8227 *Mr. Menendez. Aye.

8228 *The Clerk. Mr. Menendez votes aye.

8229 Mr. Mullin?

8230 *Mr. Mullin. Aye.

8231 *The Clerk. Mr. Mullin votes aye.

8232 Mr. Landsman?

8233 *Mr. Landsman. Aye.

8234 *The Clerk. Mr. Landsman votes aye.

8235 Ms. McClellan?

8236 *Ms. McClellan. Aye.

8237 *The Clerk. Ms. McClellan votes aye.

8238 Chairman Guthrie?

8239 *The Chair. Aye.

8240 *The Clerk. Chairman Guthrie votes aye.

8241 *The Chair. Does anyone seek recognition for answering

8242 the roll call on the Republican side?

8243 Seeing none, on the Democrat side?

8244 Seeing none, the clerk will report.

8245 [Pause.]

8246 *Mr. Pallone. No, I don't want to miss the vote.

8247 *The Chair. We will go fast.

8248 Oh, Mr. Crenshaw.

8249 *Mr. Crenshaw. Crenshaw votes aye.

8250 *The Clerk. Mr. Crenshaw votes aye.

8251 *The Chair. The clerk will report.

8252 *The Clerk. Mr. Chairman, on that vote there were 48

8253 ayes and 0 noes.

8254 *The Chair. The ayes have it, and the bill is adopted.

8255 So as we go -- this is our last bill, so I will go

8256 quick. Thank you very much for the hard work. Know that for

8257 all the time we spent on these bills today, hours, hours were

8258 spent on each bill with our staffs and our members working

8259 together, so I appreciate that very much. That way we will

8260 have a lot of work that we can get things across the floor

8261 and when we return.

8262 So the chair calls up H.R. 8005 and asks the clerk to

8263 report.

8264 *The Clerk. Committee print of H.R. --

8265 *The Chair. Without objection, the first reading of the

8266 bill is dispensed with, and the bill will be open for

8267 amendment at any point.

8268 So ordered.

8269 [The bill follows:]

8270

8271 *****COMMITTEE INSERT*****

8272

8273 *The Chair. Does anybody seek to be recognized on the
8274 bill?

8275 The gentleman from Colorado, for what purpose does from
8276 Colorado seek recognition?

8277 *Mr. Evans. Thank you, Mr. Chairman. I move to strike
8278 the last word.

8279 *The Chair. To speak on the bill, and you are
8280 recognized to speak on the bill.

8281 *Mr. Evans. Thank you, Mr. Chairman, and today I am
8282 proud to speak in strong support of my bill to help combat
8283 the scourge of fentanyl deaths driven by the proliferation of
8284 counterfeit prescription drugs. The bill is the Stop Pills
8285 That Kill Act.

8286 This common-sense legislation will help save American
8287 lives by cracking down on criminals who traffic poison
8288 disguised as prescription drugs, and by developing a
8289 comprehensive plan to address this epidemic head on.

8290 With the Trump Administration closing and securing the
8291 southern border, the United States has thankfully seen a
8292 steep decline in monthly synthetic opioid overdose deaths,
8293 from about 50,000 a month at the end of 2024 to 38,000 now.

8294 Unfortunately, Colorado has seen the exact opposite
8295 trend, with an average overdose death rate of about 800 per
8296 month at the end of 2024, increasing to 1,000 now. Because
8297 Colorado's trends did not match the national decline,

8298 Colorado has unfortunately seen more than 1,600 tragic
8299 overdose deaths that would not have existed if Colorado had
8300 simply followed the national decline.

8301 As a police officer who worked in the Denver metro area
8302 for over 10 years, I know this isn't a coincidence. When I
8303 was working to keep communities in Colorado safe from things
8304 like fentanyl poisoning our communities via counterfeit
8305 pills, ruling Democrats chose time and again to push soft-on-
8306 crime policies that released hardened criminals back into our
8307 community and lessened criminal sentencing for drugs while
8308 refusing to take on fentanyl. And that is why I am so glad
8309 that this bill, the Stop Pills That Kill Act, is being
8310 included in today's markup.

8311 The legislation is simple. Its primary provision
8312 implements new penalties and closes a sentencing loophole for
8313 counterfeit pill production so we can get the peddlers of
8314 this poison off our streets and put them in jail.

8315 It also directs the Drug Enforcement Administration to
8316 develop a comprehensive plan that enables and empowers law
8317 enforcement, regardless of agency, to investigate and seize
8318 counterfeit fentanyl or methamphetamine substances.

8319 This bill builds upon my previous efforts in this space,
8320 namely the No Fentanyl on Social Media Act which was included
8321 in the bipartisan KIDS Act, which passed the House last
8322 month. The proliferation of fentanyl-laced counterfeit pills

8323 over social media sites means that we have seen horrifying
8324 rates of fentanyl poisoning among our kids. In fact,
8325 Colorado had the second highest youth overdose death rate in
8326 the nation just two years ago, with 75 percent of those
8327 overdoses associated with fentanyl.

8328 This fight is personal to me. I will remind everyone
8329 every 15 days under the previous Administration we lost the
8330 same number of Americans to drug overdose deaths that -- as
8331 we lost in the entirety of the September 11th terrorist
8332 attacks. As a combat veteran of the global war on terror,
8333 that statistic speaks volumes and that is why I am grateful
8334 to see my legislative proposal move forward in this
8335 committee.

8336 In a minute I will offer an amendment in the nature of a
8337 substitute that rolls up two other bills to help address the
8338 counterfeit pill epidemic. These would be led by my
8339 colleagues, Rep. McDowell and Hageman. And I am grateful for
8340 their leadership, and I am grateful that this committee
8341 continues to prioritize this critically important issue to
8342 quite literally save lives.

8343 I want to express my appreciation to the chair and to
8344 the ranking member for their leadership and commitment to
8345 tackling this issue, and to the committee staff for their
8346 tireless work in helping craft and advance this legislation
8347 to keep people alive.

8348 I urge my colleagues to join me in supporting this bill,
8349 and I yield back the balance of my time.

8350 *The Chair. The gentleman yields back. Is there -- so
8351 does the gentleman have an amendment at the desk?

8352 *Mr. Evans. Yes, Chairman.

8353 *The Chair. Will the clerk report?

8354 *The Clerk. Amendment in the nature of substitute to
8355 H.R. --

8356 *The Chair. Without objection, the reading of the
8357 amendment is dispensed with.

8358 [The amendment of Mr. Evans follows:]

8359

8360 *****COMMITTEE INSERT*****

8361

8362 *The Chair. And the gentleman is recognized in support
8363 of his amendment.

8364 *Mr. Evans. Thank you, Mr. Chair.

8365 This amendment to H.R. 8005, the Stop Pills That Kill
8366 Act, would incorporate technical assistance, and rolls in two
8367 additional bills to combat counterfeit pills. The amendment
8368 in the nature of a substitute packages together the Stop
8369 Pills That Kill Act with the PRESS Act led by Representative
8370 McDowell and the Fight Illicit Pill Presses Act led by
8371 Representative Hageman. Both of these bills include
8372 important provisions that will help fight the scourge of
8373 illicit counterfeit pills by making it unlawful to import
8374 pill press equipment with the intent to illicitly produce a
8375 controlled substance, and by implementing serial number
8376 requirements for pill presses and related equipments.

8377 Again, as a police officer for over a decade I have
8378 handled illicit pills, and I know how sophisticated they are.
8379 I know how sophisticated the technology to create these
8380 illicit pills is. And so imposing accountability at the
8381 illegal manufacturer and illegal supplier level is a critical
8382 part of the fight to prevent -- or excuse me, to protect our
8383 communities from counterfeit pills. Fighting this persistent
8384 epidemic of fentanyl overdoses in America is still a top
8385 priority for me.

8386 This amendment strengthens my bill by going after the

8387 manufacturers and the suppliers and the equipment that they
8388 use to create these illicit pills. I applaud Reps. McDowell
8389 and Hageman for their work in advancing public safety.

8390 I urge support for this amendment, and I yield back.

8391 *The Chair. The gentleman yields back. Is there
8392 further discussion?

8393 Seeing none, so the question before -- if there is no
8394 further discussion, the vote occurs on the amendment.

8395 All those in favor shall signify by saying aye.

8396 Those -- all opposed, nay.

8397 The ayes have it, and the amendment is agreed to. Are
8398 there any further amendments?

8399 Seeing none, I know once we call the roll we are going
8400 to lose you, so I just want to say thank you all so much for
8401 your work today.

8402 So if there are no further amendments or discussion, the
8403 question now occurs on adopting H.R. 8005, as amended. A
8404 roll call has been requested, and the clerk will call the
8405 roll.

8406 *The Clerk. Mr. Latta?

8407 *Mr. Latta. Aye.

8408 *The Clerk. Mr. Latta votes aye.

8409 Mr. Griffith?

8410 *Mr. Griffith. Aye.

8411 *The Clerk. Mr. Griffith votes aye.

8412 Mr. Bilirakis?

8413 *Mr. Bilirakis. Aye.

8414 *The Clerk. Mr. Bilirakis votes aye.

8415 Mr. Hudson?

8416 *Mr. Hudson. Aye.

8417 *The Clerk. Mr. Hudson votes aye.

8418 Mr. Carter of Georgia?

8419 *Mr. Carter of Georgia. Aye.

8420 *The Clerk. Mr. Carter of Georgia votes aye.

8421 Mr. Palmer?

8422 [No response.]

8423 *The Clerk. Mr. Dunn?

8424 [No response.]

8425 *The Clerk. Mr. Crenshaw?

8426 *Mr. Palmer. Palmer votes aye.

8427 *The Clerk. Mr. Palmer votes aye.

8428 Mr. Dunn?

8429 [No response.]

8430 *The Clerk. Mr. Crenshaw?

8431 [No response.]

8432 *The Clerk. Mr. Joyce?

8433 *Mr. Joyce. Aye.

8434 *The Clerk. Mr. Joyce votes aye.

8435 Mr. Weber?

8436 *Mr. Weber. Aye.

8437 *The Clerk. Mr. Weber votes aye.
8438 Mr. Allen?
8439 *Mr. Allen. Aye.
8440 *The Clerk. Mr. Allen votes aye.
8441 Mr. Balderson?
8442 *Mr. Balderson. Aye.
8443 *The Clerk. Mr. Balderson votes aye.
8444 Mr. Fulcher?
8445 *Mr. Fulcher. Fulcher is aye.
8446 *The Clerk. Mr. Fulcher votes aye.
8447 Mr. Pfluger?
8448 *Mr. Pfluger. Aye.
8449 *The Clerk. Mr. Pfluger votes aye.
8450 Mrs. Harshbarger?
8451 *Mrs. Harshbarger. Aye.
8452 *The Clerk. Mrs. Harshbarger votes aye.
8453 Mrs. Miller-Meeks?
8454 [No response.]
8455 *The Clerk. Mrs. Cammack?
8456 *Mrs. Cammack. Aye.
8457 *The Clerk. Mrs. Cammack votes aye.
8458 Mr. Obernolte?
8459 *Mr. Obernolte. Aye.
8460 *The Clerk. Mr. Obernolte votes aye.
8461 Mr. James?

8462 *Mr. James. Aye.
8463 *The Clerk. Mr. James votes aye.
8464 Mr. Bentz?
8465 *Mr. Bentz. Aye.
8466 *The Clerk. Mr. Bentz votes aye.
8467 Mrs. Houchin?
8468 *Mrs. Houchin. Aye.
8469 *The Clerk. Mrs. Houchin votes aye.
8470 Mr. Fry?
8471 [No response.]
8472 *The Clerk. Ms. Lee?
8473 *Ms. Lee. Aye.
8474 *The Clerk. Ms. Lee votes aye.
8475 Mr. Langworthy?
8476 *Mr. Langworthy. Aye.
8477 *The Clerk. Mr. Langworthy votes aye.
8478 Mr. Kean?
8479 [No response.]
8480 *The Clerk. Mr. Rulli?
8481 *Mr. Rulli. Aye.
8482 *The Clerk. Mr. Rulli votes aye.
8483 Mr. Evans?
8484 *Mr. Evans. Aye.
8485 *The Clerk. Mr. Evans votes aye.
8486 Mr. Goldman?

8487 *Mr. Goldman. Aye.
8488 *The Clerk. Mr. Goldman votes aye.
8489 Mrs. Fedorchak?
8490 *Mrs. Fedorchak. Aye.
8491 *The Clerk. Mrs. Fedorchak votes aye.
8492 Mr. Pallone?
8493 *Mr. Pallone. Aye.
8494 *The Clerk. Mr. Pallone votes aye.
8495 Ms. DeGette?
8496 *Ms. DeGette. Aye.
8497 *The Clerk. Ms. DeGette votes aye.
8498 Ms. Schakowsky?
8499 *Ms. Schakowsky. Aye.
8500 *The Clerk. Ms. Schakowsky votes aye.
8501 Ms. Matsui?
8502 *Ms. Matsui. Aye.
8503 *The Clerk. Ms. Matsui votes aye.
8504 Ms. Castor?
8505 *Ms. Castor. Aye.
8506 *The Clerk. Ms. Castor votes aye.
8507 Mr. Tonko?
8508 *Mr. Tonko. No.
8509 *The Clerk. Mr. Tonko votes no.
8510 Ms. Clarke?
8511 *Ms. Clarke. No.

8512 *The Clerk. Ms. Clarke votes no.
8513 Mr. Ruiz?
8514 *Mr. Ruiz. No.
8515 *The Clerk. Mr. Ruiz --
8516 *Mr. Ruiz. Aye. Sorry, aye.
8517 *The Clerk. Mr. Ruiz is off no and on aye.
8518 Mr. Peters?
8519 *Mr. Peters. Aye.
8520 *The Clerk. Mr. Peters votes aye.
8521 Mrs. Dingell?
8522 [No response.]
8523 *The Clerk. Mr. Veasey?
8524 *Mr. Veasey. Aye.
8525 *The Clerk. Mr. Veasey votes aye.
8526 Ms. Kelly?
8527 *Ms. Kelly. No.
8528 *The Clerk. Ms. Kelly votes no.
8529 Ms. Barragan?
8530 *Ms. Barragan. Aye.
8531 *The Clerk. Ms. Barragan votes aye.
8532 Mr. Soto?
8533 *Mr. Soto. Aye.
8534 *The Clerk. Mr. Soto votes aye.
8535 Ms. Schrier?
8536 *Ms. Schrier. Aye.

8537 *The Clerk. Ms. Schrier votes aye.
8538 Mrs. Trahan?
8539 *Mrs. Trahan. Aye.
8540 *The Clerk. Mrs. Trahan votes aye.
8541 Mrs. Fletcher?
8542 *Mrs. Fletcher. Aye.
8543 *The Clerk. Mrs. Fletcher votes aye.
8544 Ms. Ocasio-Cortez?
8545 *Ms. Ocasio-Cortez. No.
8546 *The Clerk. Ms. Ocasio-Cortez votes no.
8547 Mr. Auchincloss?
8548 *Mr. Auchincloss. Aye.
8549 *The Clerk. Mr. Auchincloss votes aye.
8550 Mr. Carter of Louisiana?
8551 *Mr. Carter of Louisiana. No.
8552 *The Clerk. Mr. Carter of Louisiana votes no.
8553 Mr. Menendez?
8554 *Mr. Menendez. Aye.
8555 *The Clerk. Mr. Menendez votes aye.
8556 Mr. Mullin?
8557 *Mr. Mullin. Aye.
8558 *The Clerk. Mr. Mullin votes aye.
8559 Mr. Landsman?
8560 *Mr. Landsman. Aye.
8561 *The Clerk. Mr. Landsman votes aye.

8562 Ms. McClellan?

8563 *Ms. McClellan. Aye.

8564 *The Clerk. Ms. McClellan votes aye.

8565 Chairman Guthrie?

8566 *The Chair. Aye.

8567 *The Clerk. Chairman Guthrie votes aye.

8568 *The Chair. The gentlelady from Illinois?

8569 *Voice. [Inaudible.]

8570 *The Chair. Go from an aye to a no? Do you want to go
8571 to a no?

8572 Did you hear the gentlelady from Illinois?

8573 Please, so we can be heard.

8574 Correct me. You just want to switch from an aye to a
8575 no, correct?

8576 She wants to switch from an aye to a no.

8577 *The Clerk. Ms. Schakowsky is off aye and on no.

8578 *The Chair. Mr. Crenshaw?

8579 *Mr. Crenshaw. Aye.

8580 *The Clerk. Mr. Crenshaw votes aye.

8581 *The Chair. Does anybody else want to -- seeing none,
8582 the clerk will report.

8583 [Pause.]

8584 *The Clerk. Mr. Chairman, on that vote there were 43
8585 ayes and 6 noes.

8586 *The Chair. The ayes have it and the bill is adopted.

8587 Without objection, staff is authorized to make technical
8588 and conforming changes to the legislation approved by the
8589 Committee today.

8590 So ordered.

8591 Without objection, seeing no objection, the committee
8592 stands adjourned.

8593 [Whereupon, at 4:35 p.m., the committee was adjourned.]

EXHIBIT D

196 FERC ¶ 61,031
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Laura V. Swett, Chairman;
David Rosner, Lindsay S. See,
Judy W. Chang, and David LaCerte.

Reliability Standard(s) Pertaining to Computational Load Integration Docket No. RD26-7-000

ORDER DIRECTING THE NORTH AMERICAN ELECTRIC RELIABILITY
CORPORATION TO FILE
RELIABILITY STANDARD(S) PERTAINING TO
COMPUTATIONAL LOAD INTEGRATION

(Issued July 16, 2026)

1. As part of its ongoing oversight of the Bulk-Power System, and pursuant to section 215(d)(5) of the Federal Power Act (FPA),¹ the Commission directs the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to file by December 31, 2026, one or more new or modified Reliability Standards to address reliability risks to the Bulk-Power System associated with the integration of computational loads and any associated definitions included in the NERC Glossary of Terms Used in NERC Reliability Standards (Glossary). Likewise, pursuant to section 215(f),² the Commission directs NERC to develop revisions to NERC's Rules of Procedure, including registry criteria, necessary for registration of computational load entities and expects NERC to submit the proposed revisions by December 31, 2026. The Commission further directs NERC to submit, by March 1, 2027, an informational filing containing a workplan detailing the next steps in the standards development process for additional Reliability Standards pertaining to computational load integration.

¹ 16 U.S.C. § 824o(d)(5).

² *Id.* § 824o(f).

I. Background

A. Section 215 and the Mandatory Reliability Standards

2. Section 215 of the FPA requires the Commission to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.³ Once approved, the Reliability Standards are enforceable in the United States by the ERO, subject to Commission oversight, or by the Commission independently. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,⁴ and subsequently certified NERC.⁵

3. Section 215(d)(5) of the FPA authorizes the Commission, upon its own motion or upon complaint, to order the ERO to submit to the Commission “a proposed Reliability Standard or modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard to carry out section 215 of the [FPA].”⁶ Further, the Commission’s rules and regulations provide that the Commission, when ordering the ERO to submit new or modified Reliability Standards, may order a deadline for such submission.⁷

³ *Id.* § 824o.

⁴ *Rules Concerning Certification of the Elec. Reliability Org.; & Procs. for the Establishment, Approval, and Enf’t of Elec. Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh’g*, Order No. 672-A, 114 FERC ¶ 61,238 (2006).

⁵ *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh’g & compliance*, 117 FERC ¶ 61,126 (2006), *aff’d sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

⁶ 16 U.S.C. § 824o(d)(5); 18 C.F.R. § 39.5(f) (2026).

⁷ 18 C.F.R. § 39.5(g) (2026).

B. ANOPR and NERC's Comments

4. On October 23, 2025, the Secretary of Energy issued an advance notice of proposed rulemaking (ANOPR)⁸ pursuant to section 403 of the Department of Energy Organization Act⁹ directing the Commission to consider reforms to ensure timely and orderly interconnection of large loads to the transmission system. The Commission issued an order inviting comments on the ANOPR.¹⁰

5. Among others commenters, NERC filed comments supporting the need for prompt Commission action.¹¹ NERC states that “Reliability Standards are an important part of ensuring that the [Bulk-Power System] is prepared to meet the needs of a North American economy that is heavily reliant on the electric grid.”¹² NERC explains that the 2024 Long-Term Reliability Assessment¹³ identified that “demand growth is higher than at any point in the last two decades,”¹⁴ with particular challenges arising from large loads that “are substantially larger and constructed more quickly than prior loads

⁸ *Interconnection of Large Loads to the Interstate Transmission Sys.*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025) (ANOPR); *see also* Letter from Chris Wright, Sec’y, U.S. Dep’t of Energy (Oct. 23, 2025) (Secretary’s Letter). The full text of the ANOPR can be found at: <https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf>, and it is posted in the Commission’s eLibrary in Docket No. RM26-4-000.

⁹ 42 U.S.C. § 7173.

¹⁰ *Interconnection of Large Loads to the Interstate Transmission Sys.*, Notice Inviting Comments, Docket No. RM26-4-000 (issued Oct. 27, 2025).

¹¹ NERC, Comments, *Interconnection of Large Loads to the Interstate Transmission Sys.*, Docket No. RM26-4-000, at 1-2, 5-6 (filed Nov. 21, 2025) (NERC ANOPR Comments).

¹² *Id.* at 2.

¹³ *See* NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024) (corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

¹⁴ NERC ANOPR Comments at 5 (citations omitted).

using the [Bulk-Power System].”¹⁵ NERC further states that “this environment creates a need for quick and decisive action to address potential reliability impacts.”¹⁶

6. NERC also explains that it has initiated substantial work to assess and mitigate the reliability implications of large loads.¹⁷ NERC states that its large load action plan includes registration analysis, review of whether revisions to existing Reliability Standards could mitigate impacts to the Bulk-Power System reliability, and development of additional findings, guidance and next steps regarding large loads through an open stakeholder process.¹⁸

7. NERC’s March 20, 2026, supplemental ANOPR comments reiterate the urgency and feasibility of near-term standards development.¹⁹ NERC states the electric grid is “entering a period of load growth unprecedented in recent memory,”²⁰ and that, after further reliability assessments and stakeholder engagement, NERC has concluded that it should accelerate its action plan and “initiate efforts to update registry criteria and develop initial Reliability Standards to include large loads.”²¹ NERC further states that under its accelerated large load action plan, it intends to file initial new or modified Reliability Standards, Glossary changes, and registry criteria revisions on or before December 31, 2026.²² NERC anticipates additional Reliability Standards revisions applicable to large loads during 2027. NERC refers to the development of its initial intended filing as its Phase I Reliability Standards initiative, and it refers to the

¹⁵ *Id.* at 5-6.

¹⁶ *Id.* at 6.

¹⁷ *Id.* at 7, 12-15.

¹⁸ *Id.* at 13-17.

¹⁹ *Interconnection of Large Loads to the Interstate Transmission Sys.*, Letter from James B. Robb, President and CEO, NERC, to Chairman Swett and Commissioners, Docket No. RM26-4-000, at 2 (filed Mar. 20, 2026) (NERC ANOPR Supplemental Comments).

²⁰ *Id.* at 1.

²¹ *Id.* at 2.

²² *Id.* at 3. See also NERC, *Project 2026-02 Computational Loads* (last visited July 9, 2026), <https://www.nerc.com/standards/reliability-standards-under-development/2026-02-computational-loads> (providing additional detail on the two-phased plan).

development of subsequent filings on additional Reliability Standards pertaining to computational load integration as Phase II.

8. NERC states that on March 18, 2026, the NERC Standards Committee authorized a Standard Authorization Request proposing “Glossary updates for computational load and computational load entities along with a new Reliability Standard focused on essential actions for integrating computational loads in the near term.”²³

II. Discussion

9. We agree with NERC regarding the urgent need for action to assure that computational loads are reliably integrated into the operation of the Bulk-Power System. NERC has documented multiple grid disturbances in which computational loads have caused or contributed to the instability of the Bulk-Power System.²⁴ As noted above, NERC has developed an action plan to develop Reliability Standards for computational loads, as well as related Glossary changes and registry criteria revisions, by December 31, 2026.²⁵ While we support and encourage NERC’s activities to date, in light of the unprecedented load growth driven by data centers, it is imperative that NERC address the reliability concerns associated with computational loads in a timely manner and with greater certainty than provided by voluntary timelines.

²³ NERC ANOPR Supplemental Comments at 2. The Standard Authorization Request proposes to define “computational load” as “load comprised of power demand from information technology equipment, such as servers, storage, and networking hardware.” NERC Standard Authorization Request, *Reliability Standards to Address Computational Load – Phase I*, at 3 (Feb. 20, 2026) (revised May 11, 2026), <https://www.nerc.com/globalassets/standards/projects/2026-02/sar-comment-period/project-2026-02-computational-loads-sar-clean-052026.pdf>.

²⁴ *E.g.*, NERC Supplemental ANOPR Comments at 1 n.1; *see also* NERC, *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions* (Jan. 8, 2025), https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf; NERC, *Incident Review: Voltage-Sensitive Crypto Load Reductions* (Jan. 9, 2026), https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf; *see also* NERC, *2026 State of Reliability: Assessment Overview of 2025 Bulk Power System Performance* at 5-6 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_overview.pdf.

²⁵ NERC ANOPR Supplemental Comments at 1-3.

10. Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop one or more new or modified Reliability Standards that address reliability concerns associated with the integration of computational loads with the nation's Bulk-Power System and related Glossary changes. Consistent with NERC's action plan, NERC may submit computational load Reliability Standards in phases. To ensure timely action, we direct that NERC submit to the Commission initial "essential actions" Reliability Standards (i.e., Phase I), including any associated definitions and changes to NERC's Rules of Procedure, by December 31, 2026.²⁶ Likewise, we direct NERC to develop changes to NERC's Rules of Procedure, including registry criteria, necessary for the registration of computational load entities and expect NERC to submit the proposed revisions by December 31, 2026.

11. As mentioned above, we expect NERC to prioritize near-term measures capable of reducing identified reliability risks related to computational loads while preserving flexibility for subsequent refinements as additional experience is gained with large-load interconnections. NERC's ANOPR Supplemental Comments indicate that its accelerated action plan contemplates filing Reliability Standards resulting from Phase I by the end of 2026 and additional Reliability Standards in 2027 as needed.²⁷ Accordingly, in addition to the directives outlined above, we also direct NERC to submit by March 1, 2027 an informational filing detailing its workplan regarding its Phase II Reliability Standards pertaining to computational load integration. We recognize that both the nature of the computational load challenge and NERC's understanding of it continue to evolve and, as such, do not expect any submitted workplan to be fully comprehensive in its forecasting of future action.

The Commission orders:

(A) NERC is hereby directed to file one or more new or modified Reliability Standards to address the reliability risks associated with the integration of computational loads, including any associated Glossary definitions, by December 31, 2026, as discussed in the body of this order.

(B) NERC is hereby directed to submit revisions to NERC's Rules of Procedure, expected by December 31, 2026, as discussed in the body of this order.

²⁶ NERC ANOPR Comments at 12-17; NERC ANOPR Supplemental Comments at 1-3.

²⁷ NERC ANOPR Supplemental Comments at 3.

Docket No. RD26-7-000

- 7 -

(C) NERC is hereby directed by March 1, 2027, to submit an informational filing detailing its workplan regarding its next steps in the standards development process for additional Reliability Standards pertaining to computational load integration, as discussed in the body of this order.

By the Commission.

(S E A L)

Carlos D. Clay,
Deputy Secretary.

Document Content(s)

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EXHIBIT E

194 FERC ¶ 61,031
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Laura V. Swett, Chairman;
David Rosner, Lindsay S. See,
Judy W. Chang, and David LaCerte.

Southwest Power Pool, Inc.

Docket No. ER26-247-000

ORDER ACCEPTING TARIFF REVISIONS, SUBJECT TO CONDITION

(Issued January 14, 2026)

1. On October 24, 2025, pursuant to section 205 of the Federal Power Act (FPA)¹ and Part 35 of the Commission's regulations,² Southwest Power Pool, Inc. (SPP) submitted proposed revisions to its Open Access Transmission Tariff (Tariff) to add a High Impact Large Load (HILL) study process and High Impact Large Load Generation Assessment (HILLGA) process. As discussed below, we accept the proposed Tariff revisions,³ effective January 15, 2026, as requested, subject to condition, and direct SPP to submit a compliance filing within 30 days of the date of this order.

I. Background

A. Order No. 2003

2. In Order No. 2003,⁴ the Commission required public utilities that own, control, or operate transmission facilities to file standard generator interconnection procedures and a standard agreement to provide interconnection service to generating facilities with a capacity greater than 20 megawatts (MW). To this end, the Commission adopted the

¹ 16 U.S.C. § 824d.

² 18 C.F.R. pt. 35 (2025).

³ See Appendix for tariff records accepted in this order.

⁴ *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

pro forma Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) and required all public utilities subject to Order No. 2003 to modify their tariffs to incorporate the *pro forma* LGIP and *pro forma* LGIA.⁵

3. The Commission permitted transmission providers to seek variations from the *pro forma* LGIP and *pro forma* LGIA if those variations were “consistent with or superior to” the terms of the *pro forma* LGIP and *pro forma* LGIA.⁶ In addition, the Commission indicated that it would allow regional transmission organizations and independent system operators (RTO/ISO), such as SPP, to propose independent entity variations for pricing and non-pricing provisions, stating that RTOs/ISOs have different operating characteristics due to their sizes and locations and that an RTO/ISO is less likely to act in an unduly discriminatory manner than a transmission provider that is also a market participant.⁷ The Commission found that RTOs/ISOs “shall therefore have greater flexibility to customize [their] interconnection procedures and agreements to fit regional needs.”⁸ Under the independent entity variation standard, an RTO/ISO must demonstrate that proposed variations from the Commission’s *pro forma* LGIP and *pro forma* LGIA are just and reasonable and not unduly discriminatory or preferential and accomplish the purposes of the Commission’s final rules on generator interconnection, including Order Nos. 2003 and 2023.⁹

B. Overview of SPP’s Attachments AQ, AX, and V Processes

4. SPP evaluates a transmission customer’s request to add or modify delivery point facilities associated with load additions under existing Attachments AQ (Delivery Point

⁵ Order No. 2003, 104 FERC ¶ 61,103 at PP 1-2.

⁶ *Id.* PP 825-826. The Commission also permitted transmission providers to justify a variation from the *pro forma* LGIP or *pro forma* LGIA based on regional reliability requirements and required transmission providers to submit these regional reliability variations to the Commission for approval under the relevant reliability standard. *Id.* PP 824, 826.

⁷ *Id.* P 827.

⁸ *Id.*

⁹ See, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,084, at P 11 (2023) (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827); *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, at P 1764, *order on reh’g*, 185 FERC ¶ 61,063 (2023), *order on reh’g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

Assessment Process) and AX (Provisional Load Process) of SPP's Tariff.¹⁰ Under the Attachments AQ and AX processes, SPP studies the impacts of the requested delivery point addition or modification on the transmission system and determines what, if any, network upgrades are required to accommodate the request. The Attachment AQ process is available to a transmission customer that has sufficient existing Designated Resources to serve its forecasted load, while the Attachment AX process is available to a transmission customer that lacks sufficient existing Designated Resources.¹¹

5. Under SPP's current generator interconnection procedures, contained in Attachment V (Generator Interconnection Procedures (GIP)) of its Tariff, SPP conducts its interconnection study process, the Definitive Interconnection System Impact Study (DISIS), for which the Commission has granted an independent entity variation.¹² The DISIS is divided into a two-phased system impact study in DISIS Phase One and DISIS Phase Two, which is followed by an interconnection facilities study. The system impact study is a cluster study that evaluates the impact of each proposed interconnection request on the reliability of SPP's transmission system. DISIS Phase One and DISIS Phase Two are each followed by an interconnection customer decision point (Decision Point One and Decision Point Two, respectively). The decision points provide interconnection customers opportunities to evaluate study results and decide whether to proceed with or withdraw their interconnection requests, including posting of financial security to continue.

II. Filing

A. Overview

6. SPP states that it is experiencing an unprecedented surge in requests for large-scale load interconnections to its transmission system from data centers, cryptocurrency mining operations, electrification of industrial processes, and other energy-intensive

¹⁰ SPP, Tariff, attach. AQ, § 1 (1.0.0); *id.* attach. AQ, § 2 (2.0.0); *id.* attach. AQ, § 3 (2.0.0); *id.* attach. AX, § 1 (0.0.0); *id.* attach. AX, § 2 (0.0.0).

¹¹ Transmittal at 14 n.26; *Sw. Power Pool, Inc.*, 193 FERC ¶ 61,018, at PP 3-5 (2025). Under Attachment AX, SPP will consider the transmission customer's planned generation, in addition to its existing Designated Resources, that will be used to serve its forecasted load. *Sw. Power Pool, Inc.*, 193 FERC ¶ 61,018 at PP 5, 41.

¹² SPP, Tariff, attach. V, § 8 (Definitive Planning Phase) (25.0.0), §§ 8.4, 8.10, 8.11; *see Sw. Power Pool, Inc.*, 191 FERC ¶ 61,230, at P 71 (2025); *Sw. Power Pool, Inc.*, 193 FERC ¶ 61,171, at P 4 (2025).

facilities.¹³ Specifically, SPP explains that in every year since 2021, transmission customers, specifically large loads of over 100 MW, have submitted requests to interconnect, in the form of Attachment AQ requests, in SPP totaling multiple gigawatts (GW). SPP notes that this growing trend in large load interconnection request submissions peaked in 2022 at nearly 11 GW, but since that peak, there has been a relative drop to approximately 6 GW in 2024, which, according to SPP, could be due in part to SPP's inability to study and interconnect large loads quickly enough to meet their commercial needs.¹⁴

7. SPP contends that the emergence of large load developments, which frequently request transmission service within months rather than years of their intended commercial operation, strain the legacy regulatory frameworks, planning processes, and market mechanisms that were originally designed for incremental and predictable load growth.¹⁵ SPP explains, for example, that large load customers are requesting faster deployment timelines for generating facilities supporting the load compared to typical interconnection study timelines.¹⁶ In addition, SPP states that large loads are highly energy intensive and concentrated and pose unique challenges to maintaining the reliable and economic operation of the bulk electric transmission system.¹⁷ SPP explains that these challenges will continue to grow absent additional processes to address the reliability and operational impacts of large loads.¹⁸ SPP further contends that load-serving entities and states in the SPP region have stressed the need to expedite the process of interconnecting and serving large loads.¹⁹

8. SPP states that, to address these challenges, it proposes additional study and operational tools to integrate large loads into SPP's transmission system and to provide a limited pathway for the expedited interconnection of generating facilities that are limited and targeted to serve individual large loads. Specifically, SPP proposes to add two new

¹³ Transmittal at 1.

¹⁴ *Id.* at 8-9, figs. 2, 3.

¹⁵ *Id.* at 9-10.

¹⁶ *Id.* at 11.

¹⁷ *Id.* at 4. SPP explains that large loads present unique operational and reliability challenges because they may exhibit nonconforming load profiles, the ability to ramp rapidly and flutter, and sensitivity to power quality issues. *Id.* at 10.

¹⁸ *Id.* at 4.

¹⁹ *Id.* at 3.

processes to its Tariff: (1) the HILL study process, set forth in new Attachment BA, which includes studies and operational requirements for large loads to interconnect to SPP's transmission system; and (2) the HILLGA process, set forth in new Attachment BB, which establishes an expedited study process and new limited interconnection service for generating facilities that support a HILL.²⁰

B. HILL Study Process

9. To assess and reliably manage the challenges associated with interconnecting large loads to its transmission system, SPP proposes to: (1) establish a new category of load, termed a "HILL;" (2) establish enhanced study requirements for HILLs to enable SPP to assess the load's reliability impacts on the transmission system; and (3) establish additional, on-going operational requirements for HILLs to ensure continued reliability of the transmission system.²¹

1. Definition of HILLs

10. SPP proposes to establish a new category of load, a HILL, which will be subject to the study and operational requirements of proposed Attachment BA. SPP proposes to define a HILL as:

A new commercial or industrial load, or increase in commercial or industrial load, at a single site connected through one or more shared Points of Interconnection (POIs) or delivery points, where such load is either (1) 10 MW or more if connected to the Transmission System at a voltage level less than or equal to 69 [kilovolts (kV)]; or (2) 50 MW or more if connected to the Transmission System at a voltage level greater than 69 kV. An Electric Storage Resource is not considered a HILL. A load may be categorized as a HILL after the initial effective date of Attachment BA of the Tariff. High Impact Large Loads must register as such in accordance

²⁰ *Id.* at 11.

²¹ *Id.*

with Attachment AE²² of the Tariff and follow the processes specified in Attachment BA of the Tariff.²³

11. SPP states that large loads can differ from traditional load in several ways, but they are primarily a facility requiring a large amount of energy at a single site.²⁴ To determine what qualifies as a “large” quantity of load, SPP consulted information gathered by the North American Electric Reliability Corporation (NERC) Large Load Task Force, which showed that survey participants qualified large load as load greater than 50 MW, though it may be relative to other factors such as the voltage level at the interconnection. To reflect that the size of the load may impact SPP’s transmission system differently at different voltage levels, SPP proposes to also include as a HILL loads that are at least 10 MW that connect at or below 69 kV.²⁵ SPP explains that although the NERC definition of the Bulk Electric System includes only transmission elements of 100 kV or higher, the proposed additional 10 MW threshold is necessary due to the prevalence of 69 kV lines in the Eastern Interconnection portion of SPP’s footprint.²⁶

12. SPP argues that the proposed HILL definition is based on current industry thinking, tailored to address the topology characteristics of the SPP transmission system, and will be used to categorize the specific types of loads that will be subject to the additional studies and requirements discussed above. SPP asserts that loads that do not fall within the HILL definition will be properly excluded from these additional studies and requirements, as will preexisting loads that may meet the definition but are currently operating within the SPP transmission system. SPP argues that the proposed definition is

²² Attachment AE in the Tariff contains provisions for SPP’s Integrated Marketplace, which includes day-ahead and real-time energy and operating reserve markets and a transmission congestion rights market.

²³ SPP, Tariff, pt. I, § 1 (Definitions H) (1.0.0). Existing loads will not be considered HILLs or be subject to the requirements of Attachment BA unless they seek to increase load and otherwise meet the definitional requirements. Transmittal at 12-13.

²⁴ Transmittal at 13. Additionally, SPP asserts that large loads can have high ramp rates and the potential to exhibit sudden and rapid changes at unpredictable times. *Id.* at 12.

²⁵ *Id.* at 13.

²⁶ *Id.* (citing NERC, *Glossary of Terms*, Bulk Electric System (Oct. 1, 2025), https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf).

thus narrowly tailored and targeted to identify those loads that may present a significant operational or reliability risk to the transmission system.²⁷

2. Enhanced Study Requirements

13. SPP states that, under the current Tariff, when a network customer or transmission customer (collectively, Transmission Customer)²⁸ applies for transmission service to serve a load, the load must undergo certain studies, as provided in Attachment AQ or Attachment AX. SPP proposes, in new Attachment BA, to require a series of up to three additional studies for Transmission Customers requesting to add or modify a delivery point associated with a HILL. SPP explains that these additional studies will assess the HILL's impact on SPP's transmission system.²⁹

14. Specifically, SPP states that all requests to add or modify a delivery point to accommodate a HILL will require a HILL Delivery Point Study (HDPS), which is a broader, more rigorous set of analyses compared to those under Attachment AQ or Attachment AX due to the potential for more significant impacts to the transmission system.³⁰ SPP states that the HDPS will assess the impacts of the HILL delivery point on the transmission system using power flow and short circuit analyses, and any other analyses that may be appropriate in accordance with SPP Business Practice 7850.³¹ SPP states that if these additional HDPS analyses identify weaknesses on the transmission system caused by the interconnection of the HILL, then SPP will also perform a supplemental Electromagnetic Transient (EMT) study.³²

²⁷ *Id.* at 21-22.

²⁸ A transmission customer is defined in part as “customers receiving transmission service under Part II and Part III of this Tariff.” SPP, Tariff, pt. I, § 1 (Definitions T) (5.0.0). Part III of SPP's Tariff also refers to these customers as network customers, which is defined as “[a]n entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service [(NITS)] under Part III of the Tariff.” *Id.* § 1 (Definitions N) (3.0.0).

²⁹ Transmittal at 13-17.

³⁰ *Id.* at 15.

³¹ *Id.* at 15-16 (citing SPP, Open Access Transmission Tariff Business Practices, Business Practice 7850 (Delivery Point Additions, Modifications, and Retirements Procedures)).

³² *Id.* at 15. SPP explains that an EMT study may include EMT dynamic performance, sub-synchronous oscillation screening, converter-driven stability

15. For all requested HILL delivery point changes, SPP proposes to provide to the Transmission Customer a HILL Delivery Point Study Agreement (HDPS Agreement), and a request for any additional data or information required for the study.³³ SPP states that the Transmission Customer must return the HDPS Agreement, a \$10,000 non-refundable application fee, and a \$100,000 deposit to SPP within 30 calendar days, unless otherwise agreed upon, or SPP will deem the requested HILL delivery point change to be withdrawn.³⁴ Within 90 calendar days of receiving an executed HDPS Agreement, the study data, and deposit, SPP will complete the HDPS and issue a study report.³⁵ If SPP determines that an EMT study is necessary, it will require an additional \$200,000 deposit from the Transmission Customer. SPP states that these deposit amounts reflect the estimated costs of performing the studies under new Attachment BA. SPP explains that it must refund any excess deposit funds to the Transmission Customer, and the Transmission Customer must reimburse SPP for any unpaid study costs in excess of the deposit.³⁶

16. SPP states that the host transmission owner may also require additional analysis through a HILL Supplemental Load Connection Study (HSLCS), which will be coordinated through an agreement between the Transmission Customer and the host transmission owner.³⁷ SPP explains that the host transmission owner may require additional information from the Transmission Customer and an advance deposit of \$25,000 to conduct the study, but the host transmission owner may also determine that the HSLCS is unnecessary due to the Load Connection Study that is already required

assessments, power capability and control studies, emergency power control, fault ride-through, power quality evaluations, and model verification. *Id.* at 15 n.32.

³³ SPP, Proposed Tariff, attach. BA, § 2.1.3.4 (HILL Delivery Point Study) (0.0.0).

³⁴ Transmittal at 15; *see* SPP, Proposed Tariff, attach. BA, § 2.1.3.4 (HILL Delivery Point Study) (0.0.0), *id.* § 2.1.3.5 (Study Costs for HDPS) (0.0.0).

³⁵ SPP, Proposed Tariff, attach. BA, § 2.1.3.4 (HILL Delivery Point Study) (0.0.0). If SPP is unable to complete the HDPS within 90 days, it will notify the Transmission Customer and host transmission owner and provide an estimate of the time needed to reach a final determination. *Id.*

³⁶ Transmittal at 16; *see* SPP, Proposed Tariff, attach. BA, § 2.1.3.5 (Study Costs for HDPS) (0.0.0).

³⁷ Transmittal at 16; *see* SPP, Proposed Tariff, attach. BA, § 2.1.3.3 (HILL Supplemental Load Connection Study) (0.0.0).

under Attachment AQ or Attachment AX, as applicable.³⁸ SPP proposes that the host transmission owner must refund any excess deposit funds to the Transmission Customer, and the Transmission Customer must reimburse the host transmission owner for any unpaid study costs in excess of the deposit.³⁹

17. SPP contends that while the HDPS and HSLCS study procedures are consistent with the current study processes outlined in Attachments AQ and AX, the studies are more complex and detailed to allow SPP and the host transmission owner to study the impacts of the HILL on the transmission system.⁴⁰ SPP states that the additional studies are necessary to capture the unique behaviors of, and risks posed by, large loads and ensure reliable system performance. According to SPP, these additional studies take significantly more time and resources due to their scope, complexity, and computational demands, which, in turn, drives higher study costs compared to traditional load interconnection studies.⁴¹ SPP contends that the proposed study deposits are keyed to the anticipated costs of these HILL studies. SPP argues that the additional requirements also ensure that highly speculative HILLs are discouraged from applying to be studied.⁴²

3. Ongoing Reliability Requirements

18. SPP states that HILLs' unique characteristics necessitate that HILLs comply with certain reliability requirements. With respect to the Integrated Marketplace, SPP proposes that the market participant registering a HILL must: (1) follow all non-conforming load requirements (e.g., additional load forecast requirements, including providing an hourly load forecast value);⁴³ (2) provide load data via telemetry in real

³⁸ Transmittal at 16-17; *see* SPP, Proposed Tariff, attach. BA, § 2.1.3.3 (HILL Supplemental Load Connection Study) (0.0.0); *id.* attach. AQ, § 3 (2.0.0), § 3.1 (Load Connection Study), *id.* attach. AX, § 2 (0.0.0), § 2.1 (Load Connection Study).

³⁹ SPP, Proposed Tariff, attach. BA, § 2.1.3.3 (HILL Supplemental Load Connection Study) (0.0.0).

⁴⁰ Transmittal at 17.

⁴¹ *Id.*

⁴² *Id.* at 22.

⁴³ SPP proposes to define non-conforming load as load that cannot be generally forecasted through a mathematically derived pattern using only weather, time, season, or other normal forecasting methods. SPP, Proposed Tariff, attach. AE, § 1.1N (Definitions N) (5.0.1). SPP explains that the proposed definition distinguishes non-conforming load from load that follows the types of patterns typically used in SPP's load forecasts.

time; (3) have remote capability to disconnect the load from the transmission system made available to the transmission operator; (4) have an up/down ramp rate not exceeding 20 MW per minute unless otherwise directed; (5) include additional information with registration; and (6) not have withdrawals from the transmission system without appropriate transmission service.⁴⁴

19. Further, in order for the HILL to provide load data in real-time, SPP proposes to require the transmission owner, at the Transmission Customer's expense, to install a Phasor Measurement Unit (PMU) or similar equipment on the transmission owner's side of the HILL interconnection prior to the HILL's service commencement date.⁴⁵ SPP asserts that having this data is essential to ensuring reliability of the bulk power system and compliance with reliability standards, because it enhances SPP's ability to identify and respond to forced oscillations, monitor phase angles, assess voltage stability, and conduct post-event analysis. SPP explains that HILLs may have very fast changes in load and, because of their size and concentrated impacts, these changes can impact the transmission system so quickly that they cannot be captured by conventional supervisory control and data acquisition systems.⁴⁶

20. Additionally, SPP proposes that the Transmission Customer will be required to comply with the ride-through requirement guidelines outlined in SPP's "[HILL] Ride-Through Requirements" document, a non-Tariff document that was separately approved by SPP stakeholder working groups.⁴⁷ SPP states that, absent these ride-through requirements, HILLs have the potential to cause disturbances to the transmission system

Transmittal at 19.

⁴⁴ See SPP, Proposed Tariff, attach. AE, § 2.22 (High Impact Large Load Requirements) (0.0.0); *see also* SPP, Tariff, attach. AE, § 2.12 (Non-Conforming Load) (3.0.0) (imposing specific forecasting and data requirements for non-conforming load).

⁴⁵ Transmittal at 19; *see* SPP, Proposed Tariff, attach. BA, § 2.2.4 (Additional Requirements for Phasor Measurement Unit) (0.0.0). According to SPP, PMUs supply high-resolution, time-synchronized measurements that enable SPP to validate models, monitor dynamic performance, and detect disturbances that may otherwise lead to instability or widespread reliability impacts. Transmittal at 19.

⁴⁶ Transmittal at 19.

⁴⁷ *Id.* at 19-20. SPP is developing ride-through requirements for stand-alone HILLs, which include requirements for voltage and frequency ride through. *See* SPP documents, available at: <https://www.spp.org/spp-documents-filings/?id=19845>.

and the entire bulk power system. SPP states it will continue to modify its requirements as more defined requirements from NERC or the Commission become available.⁴⁸

21. SPP argues that the proposed ongoing operational requirements for HILLs are just and reasonable because they will afford SPP the opportunity to maintain reliable operation of the transmission system in light of the addition of HILLs to the system. SPP states that the requirements will ensure that SPP has sufficient visibility into some of the most impactful loads on the system, ensure that the utilities in the RTO footprint can serve load in real time, and ensure that the ability to shed a HILL is available, if needed.⁴⁹

C. HILLGA Process

22. SPP also proposes to implement the optional HILLGA process—a new generator interconnection service and related interconnection process—to facilitate the prompt interconnection of generating facilities that are specifically identified for and limited to serving a HILL.⁵⁰ SPP argues that the HILLGA process is just and reasonable and meets the independent entity variation standard by accomplishing the goals of Order Nos. 2003, 2023, and 2023-A by providing a path to ensure that HILLGA interconnection customers (HILLGA Customers) are able to interconnect to the transmission system, albeit on a limited basis, in a reliable, efficient, transparent, and timely manner.⁵¹

1. HILLGA Eligibility and Requirements

23. As part of the HILLGA process, SPP proposes to accept HILLGA Requests at any time.⁵² SPP contends that this proposed feature of the HILLGA process differs from the DISIS process and encourages more efficient capacity additions, a recognized goal of the

⁴⁸ Transmittal at 21 & n.58.

⁴⁹ *Id.* at 22.

⁵⁰ *Id.* at 23.

⁵¹ *Id.* at 32-33 (citing Order No. 2003, 104 FERC ¶ 61,103 at PP 822-27; Order No. 2023, 184 FERC ¶ 61,054 at P 10).

⁵² SPP proposes to define a HILLGA Request as “an Interconnection Request submitted, in the form specified in Appendix 1 to this Attachment BB, . . . to interconnect a new Generating Facility, or to increase the capacity of an Existing Generating Facility that is interconnected with the Transmission System.” SPP, Proposed Tariff, attach. BB, § 1 (Definitions) (0.0.0).

Commission.⁵³ SPP also proposes to require that all HILLGA Requests include the following: (1) an executed HILLGA Study Agreement and executed HDPS Agreement; (2) a nonrefundable application fee of \$20,000; (3) a study deposit of \$250,000 for HILLGA Requests up to 500 MW and \$500,000 for HILLGA Requests over 500 MW; (4) demonstration of site control; (5) a definitive POI; (6) the nameplate capacity, maximum injection capability, and network resource deliverability of the generating facility; (7) a security deposit equal to \$8,000/MW of the requested maximum injection capability; (8) reasonable evidence that the HILLGA Customer satisfies at least one of the listed development milestones (i.e., executed contracts, attestation that the generating facility is included in a state resource plan, and application for a land use permit); and (9) if applicable, the charging parameters and control technologies of the generating facility. SPP also proposes that the commercial operation date of the new generating facility or increase in capacity of an existing generating facility must be within five years from the execution date of the HILLGA Study Agreement.⁵⁴

24. SPP states that these requirements are similar to, but more stringent than, its existing requirements for the DISIS process. Specifically, SPP states that the application fee and security deposit for HILLGA Requests are double those in the DISIS process, and the study deposit for HILLGA Requests can reach up to \$500,000, whereas the study deposits for the DISIS process are capped at \$250,000 regardless of the size of the generating facility. Further, SPP states that the development milestone requirement for HILLGA Requests is at the beginning of the HILLGA process, whereas for the DISIS it is not until the end of the process.⁵⁵ SPP contends that these more stringent requirements will encourage the entry of commercially viable, shovel-ready generating facilities and deter speculative interconnection requests.⁵⁶

25. SPP further proposes that a HILLGA Customer must submit a separate HILLGA Request for each generating facility associated with a HILL. SPP states that, due to the limited nature of the interconnection,⁵⁷ the POI identified in the HILLGA Request must

⁵³ Transmittal at 24 (citing Order No. 2023, 184 FERC ¶ 61,054 at P 3).

⁵⁴ SPP, Proposed Tariff, attach. BB, § 8 (0.0.0), § 8.2 (Execution of HILLGA Study Agreement).

⁵⁵ Reasonable evidence of having satisfied at least one development milestone is required prior to the end of Decision Point Two in the DISIS process. SPP, Proposed Tariff, attach. V, § 8 (26.0.0), § 8.5.2 (Decision Point Two).

⁵⁶ Transmittal at 24-25.

⁵⁷ *See infra* P 66.

be no more than two substations away from the HILL at most.⁵⁸ In addition, SPP proposes that a generating facility may support multiple HILLs if no more than five substations are involved and no more than two existing transmission line segments are used between each substation. SPP states that these requirements are meant to ensure that the proposed generating facility can support the HILL(s) in a localized area.⁵⁹

26. SPP also proposes to cap the HILLGA Customer's generating facility's projected capacity accreditation MW value, as determined pursuant to Attachment AA of the Tariff,⁶⁰ at the requested MW load amount of the associated HILL, multiplied by the higher of: (1) 110% plus the highest approved Planning Reserve Margin percentage effective at the time of the HILLGA Study Agreement and outlined in the SPP Planning Criteria; or (2) 125%.⁶¹ SPP contends that this requirement will ensure that only the generation capacity necessary to serve the HILL is processed through the HILLGA process, while recognizing the load responsible entities' requirement to secure sufficient resources to cover the Planning Reserve Margin when the HILL receives long-term, firm transmission service.⁶²

2. HILLGA Study Process

27. Under the HILLGA process, SPP proposes to study HILLGA Requests to determine whether any network upgrades are needed to accommodate the generating facility's injection to the local area. SPP proposes that HILLGA Requests, which will be studied serially, will not be considered higher queued than DISIS requests but will be treated like existing generators and incorporated into SPP's Integrated Transmission Planning (ITP) models through the normal process. SPP further notes that HILLGA Requests will not appear in DISIS studies until the DISIS models have been updated to

⁵⁸ If the HILLGA Customer's generating facility is interconnecting to a 765 kV transmission line, the generating facility must be within one substation of the HILL. Transmittal at 27; *see* SPP, Proposed Tariff, attach. BB, § 3 (0.0.0), § 3.1.3 (HILLGA Requirements).

⁵⁹ Transmittal at 26-28.

⁶⁰ New thermal generating facilities in SPP have the option of using either their own design performance projections or a class average forced outage rate. New wind and solar generating facilities must either be submitted in time to be studied for the upcoming season or be assigned a default accreditation value. *See* SPP, Tariff, attach. AA, § 15 (Accredited Capacity) (4.0.0).

⁶¹ Transmittal at 26.

⁶² *Id.*

new ITP models and therefore cannot drive upgrade costs or restudies for those DISIS clusters. SPP contends that any upgrade costs required under the HILLGA process will be specific to the generating facility's injection for the local support of the HILL and will have limited impacts on other requests.⁶³

28. To allow for more rapid study and decision-making, SPP proposes to conduct a system impact study for HILLGA Requests within 90 calendar days of the HILLGA Review Period.⁶⁴ SPP further proposes that if a HILLGA Request requires a restudy due to the withdrawal or modification of a higher-queued HILLGA Request or a change to the applicable HILLGA Request's POI, SPP will notify the HILLGA Customer of the need for a restudy within 30 calendar days and will complete the restudy within 60 calendar days after the notification.⁶⁵ SPP states that the HILLGA process can accommodate this shortened timeline because HILLGA Requests will be handled through a simplified, serial process, and the generating facilities will be studied only for the limited purpose of injecting within the local area of the HILL.⁶⁶

29. SPP proposes to tender a draft HILL Generator Interconnection Agreement (HILLGIA) to the HILLGA Customer at the same time it posts the HILLGA system impact study report. SPP further proposes that the HILLGA Customer, the transmission owner, and SPP will then have 45 calendar days to negotiate the HILLGIA, unless the parties agree to a different timeline. SPP proposes that it will tender a final HILLGIA to the HILLGA Customer within 10 business days after the negotiation process concludes. Within 10 business days of receiving the final HILLGIA, the HILLGA Customer must either execute the HILLGIA or request that it be filed unexecuted with the Commission.⁶⁷

⁶³ *Id.* at 32.

⁶⁴ *Id.* at 30. The HILLGA Review Period is the time following SPP's receipt of the HILLGA Request through the time period allowed for the HILLGA Customer to cure any deficiencies in the request. SPP, Proposed Tariff, attach. BB, § 1 (Definitions) (0.0.0). During the HILLGA Review Period, SPP will validate HILLGA Requests within 15 calendar days. SPP will provide written notice of any deficiencies with the request, and the HILLGA Customer will then have 10 business days to cure any deficiencies. *Id.* § 8 (0.0.0), § 8.3 (HILLGA Review Period).

⁶⁵ SPP, Proposed Tariff, § 8 (0.0.0), § 8.8 (Restudy of HILLGA System Impact Study).

⁶⁶ Transmittal at 30-31.

⁶⁷ *Id.* at 31; *see* SPP, Proposed Tariff, attach. BB, § 11 (0.0.0), §§ 11.1 (Tender), 11.2 (Negotiation), 11.3 (Execution and Filing).

30. Additionally, SPP proposes to coordinate with affected system operators on any studies necessary to determine impacts from a HILLGA Request on an affected system.⁶⁸ SPP also proposes to determine whether a HILLGA Request has an impact on any Joint Targeted Interconnection Queue (JTIQ) upgrades.⁶⁹ If a HILLGA Request is determined to impact one or more JTIQ upgrades, SPP proposes to allocate to the HILLGA Customer a portion of the costs of a portfolio of JTIQ upgrades based on the amount of interconnection service requested in the HILLGA Request.⁷⁰

31. SPP asserts that the proposed HILLGA study process represents a reasonable approach to address large load generation needs without disadvantaging requests in the DISIS queue because the modeling and queue priority of any pending DISIS interconnection requests will not be affected by the HILLGA process. In addition, SPP asserts that the HILLGA study process will not affect the timing of any pending DISIS interconnection requests because the HILLGA process will be predominantly completed by outside consultants paid for by the HILLGA Customer through the required study deposits. SPP also argues that the HILLGA framework is narrowly tailored and targeted to allow additional generating facilities to interconnect faster and more efficiently to the transmission system to support HILLs.⁷¹

3. Load Limited Resource Interconnection Service Available to Serve HILLs

32. SPP proposes to grant HILLGA Customers a new type of interconnection service, called Load Limited Resource Interconnection Service (LLRIS), which grants limited interconnection service solely to support the associated HILL.⁷² Under LLRIS, the maximum economic capacity operating limits of the HILLGA Customer's generating

⁶⁸ Transmittal at 31; *see* SPP, Proposed Tariff, attach. BB, § 3 (0.0.0), § 3.6 (Coordination with Affected Systems).

⁶⁹ The JTIQ process involves a joint study between SPP and the Midcontinent Independent System Operator, Inc. (MISO) that aims to identify transmission network upgrades along the MISO-SPP seam that will enable future generating facilities to interconnect to the transmission grid.

⁷⁰ SPP, Proposed Tariff, attach. BB, § 3 (0.0.0), § 3.6.4 (JTIQ Provisions).

⁷¹ Transmittal at 35-38.

⁷² *Id.* at 29; *see* SPP, Proposed Tariff, attach. BB, § 3 (0.0.0), § 3.2 (Load Limited Resource Interconnection Service). LLRIS is the only "Interconnection Product Option" available to HILLGA Customers in the HILLGIA. *See* SPP, Proposed Tariff, attach. BB, app. 2 (0.0.0), art. 4 (Scope of Service).

facility cannot exceed the hourly load forecast value of the corresponding HILL except when directed by the SPP Reliability Coordinator to mitigate emergency conditions or as specified in the HILLGIA.⁷³

33. SPP proposes that the HILLGIA will automatically terminate under its own terms five years after the commercial operation date of a generating facility, which will correspondingly terminate any LLRIS granted by the HILLGIA.⁷⁴ SPP states that if the HILLGA Customer wishes for its generating facility to remain interconnected to the SPP transmission system beyond the five-year limit of LLRIS, it must submit a separate interconnection request through the DISIS process.⁷⁵ SPP asserts that the limited duration of LLRIS recognizes the importance of SPP's DISIS process and balances use of that process with the desire to interconnect HILLs in an expedited manner.⁷⁶

34. SPP states that LLRIS does not convey any type of transmission service for generating facilities serving a HILL.⁷⁷ SPP states that HILLGA Customers must obtain transmission service outside the HILLGA process to deliver the output from a generating facility to the HILL. SPP explains that, in the short term, HILLGA Customers may obtain short-term service or non-firm point-to-point transmission service, based on available transfer capability, if the delivery point was established under Attachment

⁷³ See SPP, Proposed Tariff, attach. AE, § 2.22.2 (Resource Supporting a HILL) (0.0.0). The maximum economic capacity operating limit, or economic MW level at or below a resource's maximum normal capacity operating limit used for constraining energy dispatch and contingency reserve clearing during normal system conditions, is used within SPP's algorithms when considering a resource's commitment in the day-ahead and intra-day reliability unit commitment executions in SPP's Integrated Marketplace. See SPP, Tariff, attach. AE, § 1.1M (Definitions), *id.* § 5.2.2 (Day-Ahead Reliability Unit Commitment Execution),); *id.* § 6.1.2 (Intra-Day Reliability Unit Commitment Execution).

⁷⁴ Transmittal at 36; see SPP, Proposed Tariff, attach. BB, app. 2 (0.0.0), art. 2.2 (Term of Agreement).

⁷⁵ Transmittal at 5, 29.

⁷⁶ *Id.* at 36.

⁷⁷ *Id.* at 20; see SPP, Proposed Tariff, attach. BB, §1 (Definitions) (0.0.0) (defining LLRIS); see also SPP, Proposed Tariff, attach. BB, app. 2 (0.0.0), art. 4.4 ("The execution of this HILLGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.").

AX.⁷⁸ SPP explains that, to serve a HILL on a long-term basis, HILLGA Customers must obtain long-term point-to-point transmission service or NITS through the Aggregate Transmission Service Study process under Attachment Z1 of the Tariff.⁷⁹ SPP notes that, to obtain NITS, the HILLGA Customer must also change its generation injection rights from LLRIS to Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS) through SPP's GIP.⁸⁰

III. Notice of Filing and Responsive Pleadings

35. Notice of SPP's filing was issued on October 27, 2025, with interventions and protests due on or before November 14, 2025 at 5:00 PM EST.

36. Timely notices of intervention were filed by the Louisiana Public Service Commission, the Missouri Public Service Commission, and the Public Utility Commission of Texas. Timely motions to intervene were filed by: American Clean Power Association and Advanced Power Alliance, jointly; American Electric Power Service Corporation (AEP), on behalf of its affiliates Public Service Company of Oklahoma, Southwestern Electric Power Company, AEP Oklahoma Transmission Company, Inc., and AEP Southwestern Transmission Company, Inc.; Arevon Energy, Inc.; Basin Electric Power Cooperative; Calpine Corporation; City Utilities of Springfield, Missouri; Constellation Energy Generation, LLC; EDF Power Solutions, Inc.; Electric Power Supply Association; The Empire District Electric Company; Evergy Companies;⁸¹ Geronimo Power, LLC; GridStor LLC; Kansas Electric Power Cooperative, Inc.; Longroad Energy Holdings, LLC; LS Power Development, LLC; Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM; Natural Resources Defense Council and Sustainable FERC Project, jointly; NextEra Energy Resources, LLC; Oklahoma Gas and Electric Company (OG&E); Omaha Public Power District; Orion Renewable Energy, LLC; Sierra Club; Sunflower Electric Power Corporation; Triple Oak Power LLC; Tri-State Generation and Transmission Association, Inc.; Western Farmers Electric Cooperative; and Xcel Energy Services Inc. (Xcel), on behalf of its affiliate Southwestern Public Service Company (SPS).

⁷⁸ Transmittal at 29.

⁷⁹ *Id.* at 29-30.

⁸⁰ *Id.* at 29-30.

⁸¹ Evergy Companies include the following subsidiaries of Evergy, Inc.: Evergy Kansas Central, Inc.; Every Metro, Inc.; and Evergy Missouri West, Inc.

37. On November 4, 2025, Eolian, L.P. (Eolian) filed a motion for extension of time to submit interventions and comments. On November 7, 2025, the SPP Transmission Owner Group (SPP TO Group)⁸² submitted an answer opposing the motion. On November 12, 2025, the motion for extension of time was denied.⁸³

38. Timely motions to intervene and comments in support of SPP's filing were filed by: Advanced Energy United (Advanced Energy); Eolian; ITC Great Plains, LLC (ITC Great Plains); Solar Energy Industries Association (SEIA); and SPP Market Monitoring Unit (SPP MMU). SPP TO Group filed timely comments in support of SPP's filing. Enchanted Rock, LLC (Enchanted Rock) filed a timely motion to intervene and comments requesting that the Commission accept SPP's filing subject to certain conditions.

39. On November 17, 2025, Electricity Consumers Resource Council filed an out-of-time motion to intervene. On November 24, 2025, Nebraska Public Power District filed an out-of-time motion to intervene.

40. On December 2, 2025, SPP TO Group filed a motion for leave to answer and answer. On December 4, 2025, SPP filed a motion for leave to answer and answer. On December 9, 2025, Eolian filed a motion for leave to answer and answer. On December 10, 2025, Enchanted Rock filed a motion for leave to answer and answer.

A. Comments and Answers

1. Comments

a. General Comments in Support

41. Several commenters argue that SPP's Tariff revisions to implement the HILL and HILLGA processes are just and reasonable and not unduly discriminatory or preferential.⁸⁴ Commenters assert that SPP's proposal provides a faster process for interconnecting large loads and generators serving those loads.⁸⁵ Commenters also

⁸² SPP TO Group includes: AEP, Evergy Companies, OG&E, and Xcel, on behalf of SPS.

⁸³ *Sw. Power Pool, Inc.*, Notice Denying Extension of Time, Docket No. ER26-247-000 (issued Nov. 12, 2025).

⁸⁴ Advanced Energy Comments at 1; Eolian Comments at 3; ITC Great Plains Comments at 2; SEIA Comments at 4; SPP TO Group Comments at 2, 18.

⁸⁵ Advanced Energy Comments at 4, 9; Eolian Comments at 3-4; SEIA Comments

contend that SPP's proposed HILL study process appropriately addresses the unique operating characteristics of HILLs to ensure their reliable interconnection to SPP's transmission system.⁸⁶ In addition, commenters argue that the HILL reliability requirements will avoid adverse reliability impacts after a HILL is interconnected and provide proportionate and transparent tools to manage the risks that large loads pose to the reliability of the transmission system.⁸⁷ Commenters also contend that SPP's proposed higher application fees, study deposits, and financial security requirements will prevent speculative projects and ensure only shovel-ready projects enter the HILL study process.⁸⁸

42. Commenters also assert that SPP's proposed HILLGA process addresses the need for new generation to serve large loads while ensuring that there are sufficient guardrails to avoid undue discrimination and prejudice.⁸⁹ In particular, commenters contend that SPP's proposal treats HILLGA Requests as existing generators and incorporates them into its ITP models, meaning that HILLGA Requests will not be incorporated into the DISIS models until after such models have been updated to reflect the new ITP models, which will prevent a HILLGA Request from increasing costs or restudies for interconnection customers in the DISIS.⁹⁰ Commenters also support SPP's proposed LLRIS because it does not provide transmission service, it is instead a narrower and more temporary interconnection service, and a HILLGA Customer will not be granted NRIS or ERIS unless it applies through SPP's standard interconnection processes.⁹¹

at 6; SPP TO Group Comments at 1-2.

⁸⁶ Advanced Energy United Comments at 4-5; ITC Great Plains Comments at 3-4; SPP TO Group Comments at 13.

⁸⁷ Advanced Energy Comments at 5; SEIA Comments at 4-5; SPP TO Group Comments at 6.

⁸⁸ Advanced Energy Comments at 5; SPP TO Group Comments at 15-17.

⁸⁹ Advanced Energy Comments at 6; SPP TO Group Comments at 18.

⁹⁰ Advanced Energy Comments at 8; SEIA Comments at 5; SPP TO Group Comments at 10, 19.

⁹¹ Advanced Energy Comments at 7; ITC Great Plains Comments at 6-7; SEIA Comments at 5; SPP TO Group Comments at 8-9.

b. Advanced Energy

43. In addition to its general support for the proposal as noted above, Advanced Energy asserts that SPP's proposed geographic requirements in the HILLGA process will minimize impacts on other interconnection customers by requiring the identification of the POI for the proposed generating facility and requiring that it be in close electrical proximity in the same area to the load. Advanced Energy explains that studying the local impacts and requiring that generation only serve the HILL will aim to reduce withdrawals that cause additional restudies.⁹² Advanced Energy argues that SPP's proposed HILLGA process links the generating facility with the HILL, which ensures upgrade costs are associated with that project, rather than passed on to other customers. Advanced Energy explains that these geographic limitations will lead to fewer triggered upgrades and minimal impacts on other interconnection requests, while also minimizing congestion that could have broader adverse impacts.⁹³

c. Eolian

44. Eolian generally supports SPP's proposal as noted above, but states that SPP should clarify that non-HILLGA generating facilities may serve as designated or planned generation to serve a HILL for purposes of Attachments AQ and AX.⁹⁴ Specifically, Eolian requests that SPP clarify that its Tariff revisions do not restrict non-HILLGA generating facilities from specifically serving a HILL for purposes of demonstrating adequate designated or planned generation pursuant to the relevant transmission service study. Eolian asserts that such clarification would remove any doubt that SPP's proposal would result in undue discrimination among HILLGA and non-HILLGA generating facilities that are equally technically capable of serving a HILL's needs and supporting a Transmission Customer's ability to establish transmission service for that load.⁹⁵

d. SEIA

45. While SEIA generally supports SPP's proposal as discussed above, SEIA also urges SPP to actively monitor and periodically report to the Commission and stakeholders on the effectiveness of the HILL and HILLGA processes to meet rising demand and support the reliable integration of new, concentrated large loads and local

⁹² Advanced Energy Comments at 8 (citing Transmittal at 32).

⁹³ *Id.*

⁹⁴ Eolian Comments at 12.

⁹⁵ *Id.*

interconnection of associated generating facilities.⁹⁶ In addition, SEIA contends that it is essential that SPP honor its pledge to dedicate sufficient resources to continue to meet its obligations regarding the standard interconnection process and pending DISIS requests.⁹⁷

e. SPP MMU

46. SPP MMU states that the Commission should accept SPP's filing. SPP MMU explains that it was concerned during the overall development of SPP's proposal that HILLs, whether deemed conforming or non-conforming load, were not incentivized to submit accurate operational load forecasts. SPP MMU explains that an increase in large loads on the system will only increase the current operational needs for accurate load forecasts to be used in the Reliability Unit Commitment process and that SPP should pursue future Tariff changes to address the issue. SPP MMU contends that "requirements for HILLs should either immediately apply to all load meeting [SPP's proposed] criterion; or there should be a reasonable near-term line-of-sight to applying [SPP's proposed] requirements to existing HILLs."⁹⁸ SPP MMU states that it encourages SPP to re-evaluate the grandfathering of HILL requirements after implementation of its proposed HILL and HILLGA processes.⁹⁹

f. SPP TO Group

47. As noted above, SPP TO Group supports SPP's proposal. SPP TO Group argues that interconnecting new large loads raises questions of federal and state jurisdiction. SPP TO Group asserts that SPP crafted its HILL proposal to avoid crossing into state regulation, as the proposal does not dictate terms and conditions for retail sales to end-use customers and, indeed, largely replicates SPP's existing load and generation interconnection procedures, except with stricter requirements.¹⁰⁰

g. Enchanted Rock

48. Enchanted Rock states that it generally supports SPP's efforts to establish HILL and HILLGA Tariff provisions, which facilitate the expedited, flexible, and cost-effective interconnection of large loads. Enchanted Rock, however, requests that the Commission

⁹⁶ SEIA Comments at 6.

⁹⁷ *Id.* at 6-7 (citing Transmittal at 35).

⁹⁸ SPP MMU Comments at 3.

⁹⁹ *Id.*

¹⁰⁰ SPP TO Group Comments at 20.

direct SPP to revise its capacity accreditation limits to instead be the associated HILL's requested load, multiplied by the greater of: "[(1)] 110% plus the Planning Reserve Margin outlined in the HILLGA Study Agreement; or [(2)] 150%, *rather than the currently proposed 125% value.*"¹⁰¹ Enchanted Rock explains that it is standard industry practice for generation facilities to be oversized relative to their associated HILL demand value to build in redundancies for generator failures and that large load customers' targeted availability rates of 99.9% to 99.999% requires significant oversizing of on-site generation, while back-up-only, on-site configurations require approximately 25% excess on-site capacity to ensure reliable service.¹⁰² Enchanted Rock argues that this higher capacity accreditation cap will ensure that many on-site power solutions are not unnecessarily restricted from being able to meet SPP's proposed HILL and HILLGA processes' broader goals, while also recognizing the extent to which many on-site power solutions must be oversized in order to meet large load customers' availability needs in the short term.¹⁰³

2. Answers

a. SPP

49. SPP states that, apart from Enchanted Rock, all commenters support the Commission approving SPP's proposal as just and reasonable and not unduly discriminatory or preferential.¹⁰⁴ SPP contends that while Enchanted Rock's comments request specific modifications to SPP's proposal, Enchanted Rock does not argue that SPP's proposal is unjust or unreasonable.¹⁰⁵ SPP argues that under FPA section 205, it must only show that its proposal is just and reasonable, not that it is the best approach, better than preferred alternatives, or even better than the current Tariff. SPP argues that its proposal is just and reasonable and that the Commission should accept it.¹⁰⁶

50. In response to Enchanted Rock's request to modify the capacity accreditation cap, SPP explains that it limited the size of HILLGA Requests in its proposal to ensure that

¹⁰¹ Enchanted Rock Comments at 6 (citing SPP, Proposed Tariff, attach. BB, § 3.1.3.2) (emphasis in original).

¹⁰² *Id.* at 5.

¹⁰³ *Id.* at 6-7.

¹⁰⁴ SPP Answer at 3.

¹⁰⁵ *Id.* at 3-4.

¹⁰⁶ *Id.* at 4.

the generating facility being studied would only have injection rights, or LLRIS, necessary to support the HILL. SPP asserts that this limitation prevents generating facilities from impacting other pending interconnection requests.¹⁰⁷ SPP states that nothing in its Tariff prevents a HILLGA generating facility owner from having as much redundant generating capacity as it thinks is needed to support reliability.¹⁰⁸ SPP explains, however, that its proposal will limit the injection rights to the quantity that is necessary to support the HILL. SPP argues that its proposal allows sufficient generation to be built to serve the HILL in the near-term and allows sufficient generation to be studied to satisfy the capacity needs of the HILL after it takes firm transmission service.¹⁰⁹

51. SPP further argues that SEIA's requested reporting requirement is not needed.¹¹⁰ SPP contends that it and its stakeholders continuously monitor every service provided under the Tariff and that SPP will monitor the effectiveness of the HILL and HILLGA framework in addressing the exponential growth in large loads.¹¹¹

52. In response to Eolian, SPP states that its Tariff processes remain unchanged other than those proposed in its filing.¹¹² SPP asserts that its proposal does not change the types of resources that are currently eligible to be studied in the processes outlined in Attachments AQ and AX of its Tariff. According to SPP, any generating facility that is eligible to serve load through SPP's transmission service processes today will continue to be eligible if the Commission approves SPP's proposal, which includes loads that qualify as HILLs. SPP asserts that its proposal does not contain any proposed Tariff language to the contrary and that there is no need for SPP to make any clarifications as requested by Eolian.¹¹³

¹⁰⁷ *Id.* at 6.

¹⁰⁸ *Id.* at 6-7.

¹⁰⁹ *Id.* at 7.

¹¹⁰ *Id.* (citing SEIA Comments at 6).

¹¹¹ *Id.* at 8.

¹¹² *Id.* at 9 (citing Eolian Comments at 2).

¹¹³ *Id.*

b. SPP TO Group

53. In response to Enchanted Rock's comments, SPP TO Group argues that accepting Enchanted Rock's proposed condition would not be a "minor modification" to SPP's proposal, would subvert the fundamental understanding of SPP's proposal, and would impose an entirely new rate scheme contrary to *NRG*.¹¹⁴ SPP TO Group states that the entire point of limiting HILLGA generators to LLRIS is to "grant[] limited interconnection rights solely to support the HILL, which limits both the impacts of the generation on SPP's [t]ransmission [s]ystem and potential [n]etwork [u]pgrade costs." SPP TO Group argues that SPP stakeholders supported and voted in favor of SPP's proposal because it was narrowly tailored to limit HILLGA generators to serving a designated HILL.¹¹⁵

3. Answers to Answers

a. Eolian

54. Eolian states that it requested clarification from SPP that its Tariff revisions would not restrict non-HILLGA generating facilities from specifically serving HILLs for the purposes of demonstrating adequate designated or planned resources pursuant to the relevant transmission study.¹¹⁶ Eolian asserts that SPP's answer explained that SPP's proposal does not change the types of generating facilities that are currently eligible to be studied in the processes outlined in Attachments AQ and AX of its Tariff, that any generating facility that is eligible to serve load through SPP's transmission service processes today will continue to be eligible if the Commission approves SPP's proposal, and that SPP's proposal does not contain any proposed Tariff language to the contrary.¹¹⁷ Eolian states that SPP's answer satisfies Eolian's prior request for clarification.¹¹⁸

b. Enchanted Rock

55. Enchanted Rock states that it recognizes SPP's clarification in its answer that the HILLGA process, if approved, would not interfere with a generator's installation of

¹¹⁴ SPP TO Group Answer at 5 (citing *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017) (*NRG*)).

¹¹⁵ *Id.* at 6.

¹¹⁶ Eolian Answer at 1 (citing Eolian Comments at 12).

¹¹⁷ *Id.* (citing SPP Answer at 9).

¹¹⁸ *Id.*

redundant on-site capacity and, accordingly, requests that the Commission accept SPP's proposal without condition.¹¹⁹

IV. Discussion

A. Procedural Matters

56. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2025), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

57. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2025), we grant Electricity Consumers Resource Council's and Nebraska Public Power District's late-filed motions to intervene given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

58. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2025), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept the answers filed by SPP TO Group, SPP, Eolian, and Enchanted Rock because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

59. As discussed below, we find SPP's proposed Tariff revisions to establish the HILL and HILLGA processes to be just and reasonable and not unduly discriminatory or preferential and, therefore, accept them, effective January 15, 2026, as requested, subject to condition,¹²⁰ and direct SPP to submit a compliance filing within 30 days of the date of this order.

60. SPP has shown that unprecedented growth in large loads in the SPP region presents significant and unique operational and planning challenges. We find that SPP's proposed HILL and HILLGA processes are a just and reasonable and not unduly discriminatory or preferential approach to addressing these challenges, while maintaining the reliable operation of SPP's transmission system. We also find that SPP's proposed Tariff revisions implementing the HILLGA process accomplish the purposes of the Commission's final rules on generator interconnection, including Order Nos. 2003 and

¹¹⁹ Enchanted Rock Answer at 2-3 (citing SPP Answer at 7).

¹²⁰ See *NRG*, 862 F.3d at 114-15 (discussing the Commission's authority to propose modifications to a utility's FPA section 205 rate proposal).

2023, by helping to ensure that interconnection customers seeking to serve HILLs in SPP are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.¹²¹ Therefore, we find that SPP's proposed Tariff revisions implementing the HILLGA process meet the independent entity variation standard.

1. HILL Process

61. We find that SPP has demonstrated that its proposed HILL process—including the definition of HILLs, study requirements for HILLs, and ongoing reliability requirements for HILLs—is a just and reasonable and not unduly discriminatory or preferential approach for integrating Transmission Customers' new large loads into SPP's transmission system in a manner that enables SPP to maintain reliable operation of that system. We find that it is reasonable to subject HILLs, as SPP proposes to define them, to additional study requirements and the other proposed requirements set forth in Attachment BA given their unique operating characteristics. We also find that the voltage criterion in the proposed HILL definition recognizes that different-size loads may have different impacts on the transmission system depending on the voltage level at which they interconnect and reflects the prevalence of 69 kV transmission lines in the Eastern Interconnection portion of SPP's footprint.

62. Regarding SPP's proposed HDPS, EMT study, and HSLCS, we find that these proposed study requirements for HILLs, in conjunction with the existing study requirements in Attachments AQ and AX of SPP's Tariff, will help to ensure the reliable integration of Transmission Customers' HILLs into SPP's transmission system. We find that the proposed study requirements for HILLs will provide SPP with information about their impact on SPP's transmission system, including the transmission system's ability to withstand and control disturbances by the HILL at the point of interconnection. In addition, we find that the proposed study deposits reflect the estimated costs of the studies to be performed and will help discourage speculative HILL study requests. Further, refunding any excess portion of the deposit ensures Transmission Customers will pay only the actual study amount. We further find that allocating the study deposits and study costs to the Transmission Customer requesting a delivery point modification associated with a HILL is consistent with the Commission's cost causation principle.¹²²

¹²¹ Order No. 2003, 104 FERC ¶ 61,103 at PP 26, 827; Order No. 2023, 184 FERC ¶ 61,054 at P 1.

¹²² The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014) (citing *Nat'l Ass'n of Regul. Util. Comm'nrs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007)).

63. We find that the proposed ongoing reliability requirements related to HILLs, including, among other things, non-conforming load forecasting, PMU, and ride-through requirements, are also just and reasonable and not unduly discriminatory or preferential. We find that the proposed requirements will allow SPP to maintain reliable operation of its transmission system by increasing SPP's visibility, providing necessary data, and imposing real-time operational safeguards for HILLs.

2. HILLGA Process

64. As noted above, the Commission applies an independent entity variation standard to evaluate RTO/ISO proposals for deviations from the Commission's *pro forma* LGIP and *pro forma* LGIA.¹²³ Under the independent entity variation standard, SPP must demonstrate that its proposed variations are just and reasonable and not unduly discriminatory or preferential and accomplish the purposes of the Commission's final rules on generator interconnection, including, as relevant here, Order Nos. 2003 and 2023.¹²⁴ We grant SPP an independent entity variation for its proposed HILLGA process because we find that the proposed process is just and reasonable and not unduly discriminatory or preferential and accomplishes the purposes of Order Nos. 2003 and 2023 to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner.¹²⁵ As discussed further below, we find that SPP's HILLGA process reasonably provides a flexible, expedited, and separate serial interconnection process that will facilitate the prompt interconnection of generating facilities that are limited to serving a HILL in the same local area.

65. We find that the more stringent eligibility requirements for the HILLGA process, compared to the requirements set forth in the Commission's *pro forma* LGIP, are just and reasonable and not unduly discriminatory or preferential because they will help deter speculative interconnection requests from entering the expedited interconnection process. Specifically, we find that the more stringent financial commitments, the obligation to satisfy a development milestone earlier in the process, and the requirement that

¹²³ See, e.g., Order No. 2003, 104 FERC ¶ 61,103 at P 827; Order No. 2023, 184 FERC ¶ 61,054 at P 1764 & n.3346.

¹²⁴ See, e.g., *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,215, at P 30 (2023) ("Under the independent entity variation standard, SPP must demonstrate that its proposed variations are just and reasonable and not unduly discriminatory or preferential, and accomplish the purposes of the Commission's rulemakings establishing the *pro forma* generator interconnection procedures and agreements.").

¹²⁵ See, e.g., Order No. 2023, 184 FERC ¶ 61,054 at P 693 ("This approach achieves the Commission's goals of ensuring that interconnection customers are able to interconnect in a reliable, efficient, transparent, and timely manner.").

generating facilities enter commercial operation within five years of executing the HILLGA Study Agreement, among other requirements, will encourage the submission of more commercially ready and less speculative interconnection requests.

66. We further find that SPP's proposed HILLGA substation and transmission line segment requirements are just and reasonable and not unduly discriminatory or preferential because they help to preserve the local, limited nature of SPP's proposed LLRIS. These requirements help to ensure that a HILLGA interconnection will have limited impacts on SPP's transmission system by providing that the generator's POI must be in the same local area as the HILL that the HILLGA Customer will serve. Similarly, SPP proposes to cap the HILLGA Customer's generating facility's projected capacity accreditation value at the requested load amount of the associated HILL(s), multiplied by the higher of: (1) 110% plus the highest approved Planning Reserve Margin percentage effective at the time of the HILLGA Study Agreement and outlined in the SPP Planning Criteria; or (2) 125%.¹²⁶ We find that SPP's proposed cap on the projected capacity accreditation value helps to ensure that only the generation capacity necessary to serve the HILL is studied through the HILLGA process, while recognizing that the relevant load responsible entity must secure sufficient resources to cover the Planning Reserve Margin that it will be required to carry when the HILL receives long-term, firm transmission service.¹²⁷

67. We also find that SPP's proposal is just and reasonable and not unduly discriminatory or preferential because we agree with SPP that the "HILLGA presents a reasonable approach to address [the] large load generation needs without disadvantaging

¹²⁶ Transmittal at 26.

¹²⁷ In its comments, Enchanted Rock initially requested that the Commission accept SPP's proposal but only on the condition that SPP change the second of the proposed values (i.e., the 125%) to 150%. Enchanted Rock Comments at 6. In its answer, however, Enchanted Rock states that SPP's answer clarifies that the HILLGA proposal would not interfere with an interconnection customer's installation of redundant on-site capacity to support reliability and, therefore, asks the Commission to accept SPP's HILLGA proposal without condition. Enchanted Rock Answer at 1-3. In any event, for the reasons discussed above, we find SPP's proposed cap just and reasonable, and under FPA section 205, SPP need not show that its proposal is the most just and reasonable among all possible alternatives so long as it demonstrates that the proposal is just and reasonable. *See, e.g., Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (describing the Commission's authority under section 205 of the FPA as "limited to an inquiry into whether the rates proposed by a utility are reasonable—and not to extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.").

requests in the DISIS queue.”¹²⁸ For instance, SPP proposes to accept HILLGA Requests at any time and complete the entire HILLGA process within 150 days, which is a significantly faster timeline than the current DISIS process, which, as designed, takes 12 months to complete.¹²⁹ At the same time, HILLGA Requests will not be considered higher queued than pending interconnection requests in the standard DISIS queue and will not appear in the DISIS models until such models have been updated to include new ITP models. As a result, the proposed Tariff revisions are designed to not drive increased network upgrade costs or risk of restudies for pending DISIS interconnection requests. In addition, SPP states that the HILLGA process will not affect the timing of any pending DISIS interconnection requests because the HILLGA process will be predominantly completed by outside consultants paid for by the HILLGA Customer through the required study deposits.

68. Regarding LLRIS, we find that SPP’s proposal is just and reasonable and not unduly discriminatory or preferential because it limits a HILLGA Customer to only serving a HILL or HILLs located in the same local area as the POI for its generating facility and, thus, mitigates the generating facility’s impacts on SPP’s transmission system. In addition, we find that it is a reasonable component of SPP’s proposal to limit LLRIS to a term of five years. Because HILLGA Customers with LLRIS have interconnection service that is limited to a five-year term and limited to serving specific HILL or HILLs, we find it reasonable that these customers are only eligible to obtain non-firm point-to-point and short-term point-to-point service without being studied in the Aggregate Transmission Service Study process or obtaining different interconnection service.¹³⁰ We note that the expiration of LLRIS also ensures that any generating facilities that interconnect to the transmission system will eventually go through SPP’s standard interconnection procedures, including all necessary studies, if they are to be interconnected for longer than five years.

¹²⁸ Transmittal at 35.

¹²⁹ *Id.* at 36-37.

¹³⁰ Non-firm point-to-point transmission service includes the transmission of energy on an hourly, daily, weekly, or monthly basis, not to exceed one month’s reservation. *See* SPP, Tariff, Pt. II, § 14.5 (Classification of Non-Firm Point-To-Point Transmission Service). Short-term firm point-to-point transmission service is firm point-to-point transmission service that provides firm deliveries of capacity and energy from the point(s) of receipt to the point(s) of delivery with a term of less than one year. *See also id.*, Pt. I, § 1.1S (Definitions); *id.*, Pt. II, § 13.7 (Classification of Firm Transmission Service); *id.*, attach. P (Transmission Service Timing Requirements).

69. Finally, we find that SPP's proposed HILLGA process accomplishes the purposes of Order Nos. 2003 and 2023 to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner. We find that SPP's HILLGA-related revisions, taken together, accomplish these purposes because they will help ensure that HILLGA Customers seeking to serve HILLs are able to interconnect to the transmission system in a timely manner and increase the speed of interconnection queue processing.¹³¹ Therefore, we find that SPP's proposed Tariff revisions implementing the HILLGA process meet the independent entity variation standard.

3. Miscellaneous Issues

70. As noted above, SEIA asserts that the "Commission should encourage SPP to undertake ongoing monitoring and reporting commitments regarding its proposed HILLS/HILLGA processes."¹³² We decline SEIA's request because SPP has demonstrated that the proposed HILL and HILLGA processes are just and reasonable for the reasons discussed above.¹³³ Moreover, we note that SPP asserts that it will monitor the effectiveness of the HILL and HILLGA processes just like it continuously monitors every service provided under its Tariff.¹³⁴

71. However, we note that SPP's filing contains several ministerial errors throughout proposed Attachments BA and BB: (1) incorrect usage of the acronym "HSCS" instead of "HSLCS" in Attachment BA section 2.1.3.3; (2) redundant wording in the following sentence in Attachment BA section 2.1.3.4: "The Transmission Provider will perform a supplemental assessment, *in addition to the studies required pursuant to Attachment AQ and AX of the Tariff*, of the impact of a requested HILL delivery point configuration change on the Transmission System for the full requested term, *in addition to the studies required in Attachment AX and Attachment AX of the Tariff*";¹³⁵ (3) failure to specify "90-Calendar Day extension" in the following sentence in Attachment BA, section 2.1.3.4: "The Transmission Provider may grant a 90-day extension for completion of

¹³¹ See, e.g., Order No. 2023, 184 FERC ¶ 61,054 at PP 4, 693.

¹³² SEIA Comments at 7.

¹³³ See *Cities of Bethany v. FERC*, 727 F.2d at 1136.

¹³⁴ SPP Answer at 8.

¹³⁵ SPP, Proposed Tariff, attach. BA, § 2 (0.0.0), § 2.1.3.4 (HILL Delivery Point Study) (emphasis added).

such negotiations”;¹³⁶ (4) inconsistent usage of the term “Transmission Owner” in Attachment BA section 2.2.4 and the term “Host Transmission Owner” in the remainder of Attachment BA; (5) inclusion of the capitalized term “High Impact Large Load Generation Assessment Study Procedures” in the defined term “High Impact Large Load Generation Assessment Request” in Attachment BB section 1, which is not defined or used elsewhere in Attachment BB; and (6) incorrect usage of the acronym “HILGA” instead of “HILLGA” in Attachment BB sections 3.4.4.1 and 4.4. Therefore, we direct SPP to submit, within 30 days of the date of this order, a compliance filing that corrects the ministerial errors listed above.

The Commission orders:

(A) SPP’s proposed Tariff revisions are hereby accepted, effective January 15, 2026, as requested, subject to condition, as discussed in the body of this order.

(B) SPP is hereby directed to submit a compliance filing, within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Rosner is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Secretary.

¹³⁶ *Id.*

Appendix – Tariff Records

Southwest Power Pool, Inc.
Open Access Transmission Tariff, Sixth Revised Volume No. 1

- [Table of Contents, Table of Contents \(17.0.6\)](#)
- [Definitions H, 1 Definitions H \(1.0.0\)](#)
- [Definitions P, 1 Definitions P \(4.0.0\)](#)
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- [Attachment AE \(MPL\), Attachment AE Integrated Marketplace \(28.0.0\)](#)
- [Att. AE \(MPL\) 1.1 N, Attachment AE \(MPL\) Section 1.1 N \(5.0.1\)](#)
- [Att. AE \(MPL\) 2.2, Attachment AE \(MPL\) Section 2.2 \(22.0.0\)](#)
- [Att. AE \(MPL\) 2.5, Attachment AE \(MPL\) Section 2.5 \(1.0.0\)](#)
- [Att. AE \(MPL\) 2.22, Attachment AE \(MPL\) Section 2.22 \(0.0.0\)](#)
- [Att. AE \(MPL\) 2.22.1, Attachment AE \(MPL\) Section 2.22.1 \(0.0.0\)](#)
- [Att. AE \(MPL\) 2.22.2, Attachment AE \(MPL\) Section 2.22.2 \(0.0.0\)](#)
- [Attachment AQ Section 1, Attachment AQ Section 1 \(2.0.0\)](#)
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- [Att. AX Section 2, Attachment AX Section 2 \(1.0.0\)](#)
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- [Attachment BA, Attachment BA High Impact Large Load \(0.0.0\)](#)
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- [Att. BB Section 11, Attachment BB Section 11 \(0.0.0\)](#)

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- [Att. BB Section 12, Attachment BB Section 12 \(0.0.0\)](#)
- [Att. BB Section 13, Attachment BB Section 13 \(0.0.0\)](#)
- [Att. BB App 1, Attachment BB Appendix 1 \(0.0.0\)](#)
- [Att. BB App 2, Attachment BB Appendix 2 \(0.0.0\)](#)
- [Att. BB App 3, Attachment BB Appendix 3 \(0.0.0\)](#)
- [Att. BB App 4, Attachment BB Appendix 4 \(0.0.0\)](#)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southwest Power Pool, Inc.

Docket No. ER26-247-000

(Issued January 14, 2026)

ROSNER, Commissioner, *concurring*:

1. Today's order accepts SPP's proposal to establish new study processes for new High Impact Large Loads (HILLs) and associated generation through the High Impact Large Load Generation Assessment (HILLGA). Together, these processes will enable SPP to efficiently identify new large loads, expedite the interconnection of new generation needed to serve them, and protect the reliability of the bulk power system. The proposal also encourages "bring-your-own-new-generation" solutions in SPP, which will enable rapid interconnection of new large loads without raising costs or threatening electric reliability for other customers. I concur to highlight SPP's pragmatic steps to support economic growth in its footprint and call on other transmission providers across the country to consider similar proposals through FPA section 205 filings.

2. The HILLs and HILLGA processes work together to pair shovel-ready generation with large loads and allow them to interconnect to the grid in less than half the time typically required for generators to clear SPP's generator interconnection queue. The secret sauce behind SPP's proposal is Load Limited Resource Interconnection Service (LLRIS), a new interconnection service that limits the amount of power a generator can put on the SPP grid to the forecasted hourly load of the nearby large load it serves. Because the generator's output is matched to the large load's demand, the impacts of adding load and generation to the transmission system effectively cancel each other out, which minimizes the need for time-consuming transmission upgrades. SPP's proposal is grounded in physics, takes a harder look at reliability impacts of large loads on the grid than current practice requires, and unlocks large load opportunities while protecting other customers from rising bills.

3. There are also clear parallels between SPP's approach in its HILLs and HILLGA processes and the new transmission services the Commission recently directed PJM to create for load co-located with generation.¹ While the mechanics of these approaches are distinct between the different regions, the practical outcome is similar: they both enable new generation needed to serve new large loads to connect to the grid faster and at lower

¹ See 193 FERC ¶ 61,217 at PP 200-03; 234.

cost. The common thread is a recognition that when generation is paired with load that is physically proximate, the impacts on the transmission system are lower than they are in the status quo, in which large loads and generation are planned separately.

4. I also note that SPP's proposal is another step towards realizing the goals of Secretary Wright's Large Load ANOPR proposal in three important ways: first, it pairs new large loads and new generation to connect them to the grid rapidly and reliably;² second, it minimizes costs borne by other customers;³ and third, it does so through an FPA section 205 filing, rather than waiting on the Commission to require such action.⁴

5. Today's order is a productive step toward facilitating the energy needed to win the AI race, bring back American manufacturing, and deliver the reliable and affordable energy on which families and small businesses depend. I encourage other transmission providers to take note of the innovative approach SPP proposed in this filing, and to consider proposing similar solutions tailored to meet the needs within their own footprints.

For these reasons, I respectfully concur.

David Rosner
Commissioner

² See U.S. Department of Energy, Secretary of Energy, Direction that the Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act (Oct. 23, 2025) at P 20.

³ See *Id.* at P 25.

⁴ See *Id.* at P 32.

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EXHIBIT F

195 FERC ¶ 61,211
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Laura V. Swett, Chairman;
David Rosner, Lindsay S. See,
Judy W. Chang, and David LaCerte.

PJM Interconnection, L.L.C.

Docket No. EL26-67-000

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company

Docket No. EL26-67-000

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PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Silver Run Electric, LLC
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

ORDER INSTITUTING PROCEEDING

UNDER SECTION 206 OF THE FEDERAL POWER ACT

(Issued June 18, 2026)

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1. Over the past year, the Commission has taken action in numerous dockets¹ to address issues related to (a) unprecedented increases in requests for transmission service to serve large loads² and (b) growing interest in the co-location of loads with generating facilities (co-location arrangements³). Separately, the Secretary of Energy (Secretary) released an advance notice of proposed rulemaking (ANOPR) in October 2025. The ANOPR, issued pursuant to section 403 of the Department of Energy Organization Act,⁴ directed the Commission to consider taking additional actions to address the addition of large and co-located loads to the transmission system.⁵ The records in these proceedings illustrate a host of urgent challenges associated with providing the transmission service needed to serve the ongoing influx of large loads while maintaining reliability and affordability. In particular, stakeholders have expressed concerns that large loads are not efficiently and appropriately integrated onto the transmission system; have identified a

¹ See, e.g., *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 (2025) (PJM Show Cause Order); *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025) (PJM Co-Location Order); *Sw. Power Pool, Inc.*, 194 FERC ¶ 61,031 (2026) (SPP HILL Order); *Sw. Power Pool, Inc.*, 195 FERC ¶ 61,196 (2026) (SPP CHILLS Order); see also, e.g., *Duke Energy Carolinas, LLC*, 193 FERC ¶ 61,237 (2025); *Commonwealth Edison Co.*, 194 FERC ¶ 61,181 (2026).

² As explained below, it appears that it would be reasonable to define a large load as (1) a new commercial or industrial customer, (2) located at a single site behind one or more points of interconnection, (3) that has a peak load of 50 MW or greater, (4) interconnects to the transmission system at a voltage level of greater than 69 kV, and (5) is not part of a co-location arrangement. See *infra* P 58.

³ The PJM Co-Location Order defined co-located load as “configuration [that] refers to end-use customer load that is physically connected to the facilities of an existing or planned Customer Facility on the Interconnection Customer’s side of the Point of Interconnection to the PJM Transmission System.” PJM Co-Location Order, 193 FERC ¶ 61,217 at P 164 (alterations in original). The PJM Co-Location Order used the term co-location arrangement when referring to both the co-located load and the associated generator. *Id.* P 3.

⁴ 42 U.S.C. § 7173.

⁵ See *Interconnection of Large Loads to the Interstate Transmission System*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025) (ANOPR); see also Letter from Chris Wright, Sec’y, U.S. Dep’t of Energy, Docket No. RM26-4-000 (Oct. 23, 2025). The ANOPR uses the term “hybrid facilities,” which it explains are large loads that “share a point of interconnection with new or existing generation facilities.” ANOPR at P 12. In this order, we use the term co-located load.

number of unique challenges that large load integration poses for the reliable operation of that system; and have debated how best to ensure that the rates, terms, and conditions of transmission service remain just and reasonable as more and more large loads are onboarded onto that system.⁶ The records in these proceedings likewise present serious concerns about the lack of clarity and consistency in Regional Transmission Organization or Independent System Operator (RTO/ISO) tariffs—including with respect to the rates, terms, and conditions of service that apply to flexible large loads, co-location arrangements, load with behind the meter generation, and generating facilities with electrically proximate large load⁷ or co-located load.

2. The findings in several recent Commission proceedings establish the foundations of a just and reasonable framework for addressing these concerns and ensuring the timely, efficient, and reliable integration of large and co-located loads onto the transmission system. For example, Southwest Power Pool, Inc. (SPP) has recently taken a number of innovative and proactive steps to address the challenges of integrating large loads, co-located loads, and/or generation and electrically proximate large load onto the transmission system while ensuring that its tariff remains just and reasonable.⁸ PJM Interconnection, L.L.C. (PJM), through the Commission's show cause proceedings, is also addressing the rates, terms, and conditions of service that apply to co-location arrangements and establishing new transmission services that reflect the ability of Eligible Customers⁹ taking transmission service on behalf of Eligible Load to limit their

⁶ Throughout this order we rely on comments and answers filed in response to the ANOPR in Docket No. RM26-4-000 and all referenced comments in this order were filed in that docket, unless otherwise noted. A full list of commenter names and abbreviations is attached to this order as an Appendix. Additionally, we have relied on the discussions held in the Federal and State Current Issues Collaborative in Docket No. AD24-7-000 (NARUC Collaborative). All entities who wish to participate in this docket, regardless of participation in the ANOPR proceeding or NARUC Collaborative, should file to intervene in Docket No. EL26-67-000.

⁷ As explained below, for purposes of this order, an “electrically proximate large load” is a large load, as defined in this order, that is sufficiently electrically close to the interconnection customer's requested point of interconnection, such that the impact on the transmission system of the combination of the generating facility and the load, with the exception of the transmission facilities between the two, will be effectively the same as if they were located at the same substation (e.g., large load that is located no more than two substations away from the generating facility). *See infra* P 94.

⁸ SPP HILL Order, 194 FERC ¶ 61,031; SPP CHILLS Order, 195 FERC ¶ 61,196.

⁹ PJM's Tariff defines an Eligible Customer as:

withdrawals from the transmission system under certain conditions.¹⁰ PJM has also taken steps attempting to enhance resource adequacy in the region.¹¹ Because the Commission is addressing its concerns related to co-located load in the separate and ongoing Federal Power Act (FPA) section 206¹² proceeding involving PJM, this order is limited to addressing the integration of large loads that are *not* co-located with generation. While we appreciate the steps PJM has already taken with respect to co-location arrangements, we note that PJM has not yet proposed tariff revisions to address the challenges associated with the integration of large loads.

3. As discussed below, we find that PJM's existing Open Access Transmission Tariff (Tariff) appears to be unjust, unreasonable, or unduly discriminatory or preferential. We

-
- (i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale . . .
 - (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VIII, Eligible Customer shall mean only those Eligible Customers that have submitted an Application and Study Agreement.

PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT, pt. VIII, § 400 (Definitions E) (2.0.0) (PJM Tariff).

¹⁰ PJM Show Cause Order, 190 FERC ¶ 61,115; PJM Co-Location Order, 193 FERC ¶ 61,217, *order on reh'g*, 195 FERC ¶ 61,209 (2026) (PJM Co-Location Rehearing Order). In the PJM Co-Location Rehearing Order, the Commission used the term Eligible Load to refer to co-located load and/or load with Behind the Meter Generation. PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209 at P 91.

¹¹ *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,197 (2026) (PJM EIT Order); *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, *order on reh'g*, 192 FERC ¶ 61,085 (2025); *see also* PJM Interconnection, L.L.C., Informational Report, Docket No. EL25-49-000, et al. (filed Jan. 20, 2026); PJM Interconnection, L.L.C., Supplemental Informational Report, Docket Nos. EL25-49-000, et al. (filed Feb. 23, 2026); PJM Interconnection, L.L.C., Second Supplemental Informational Report, Docket No. EL25-49-000, et al. (filed Mar. 9, 2026).

¹² 16 U.S.C. § 824e.

thus institute a show cause proceeding pursuant to section 206 of the FPA, and we direct PJM and the Transmission Owners,¹³ within 60 days of the date of this order, to either:

(1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential without provisions addressing:

(a) the application process, study procedures, and ongoing operational requirements that apply to Eligible Customers seeking transmission service on behalf of large loads;

(b) additional transparency concerning the Network Upgrade¹⁴ costs to provide transmission service to Eligible Customers on behalf of large loads, a *pro forma* cost recovery agreement between PJM, the relevant transmission owner, and Eligible Customer taking transmission service on behalf of the large load to mitigate the risk of cost shifting among transmission customers, and a mechanism to ensure such payments are appropriately credited toward transmission owners' transmission revenue requirements consistent with the Commission's cost-of-service regulations;

(c) transmission services that reflect Eligible Customers taking transmission service on behalf of flexible large loads that are willing and able to limit their use of the transmission system under certain conditions;¹⁵ and

¹³ Transmission Owners refers to the entities listed in the caption of this order. We recognize that PJM's transmission owners include entities that are not subject to the Commission's jurisdiction because they are not public utilities pursuant to section 201(f) of the FPA. *See* 16 U.S.C. § 824(f); *Sw. Power Pool, Inc.*, 180 FERC ¶ 61,022, at PP 44-45 (2022). Accordingly, the Commission has not included AMP Transmission, LLC; City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power; City of Hamilton, OH; East Kentucky Power Cooperative, Inc.; and Southern Maryland Electric Cooperative, Inc. here as Transmission Owners that must respond to this order to show cause. Nonetheless, the Commission retains the authority to review each entity's formula rates as a component of PJM's Tariff in an order to show cause directed towards PJM, and PJM must respond to this order regarding the non-public utilities' PJM Tariff provisions on file with the Commission. *See Sw. Power Pool, Inc.*, 180 FERC ¶ 61,022 at P 40.

¹⁴ Capitalized terms not otherwise defined herein have the meanings ascribed to them in the Tariff.

¹⁵ As explained below, for purpose of this order, "flexible" large loads are a subset of large loads, as used in this order, that are not co-located with generation, but are

(d) the rates, terms, and conditions of service applicable to interconnection customers serving electrically proximate large load or co-located load; or

(2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential and, therefore, proceeds to establish a replacement Tariff.

4. We are also concerned with PJM's need to ensure adequate generation to serve new large loads.¹⁶ We therefore direct PJM to submit, within 30 days of the date of issuance of this order, an informational report on how PJM intends to ensure that adequate generation will be available to serve existing and new large loads, as detailed later in this order.

5. We recognize that large loads, including data centers, are actively working with transmission owners and other relevant entities to interconnect to, and to take service from, the transmission system. We appreciate that different large loads are currently at different stages of that process. We also understand that large loads and Eligible Customers taking transmission service on behalf of large loads are negotiating, entering into, and/or have executed various agreements related to interconnecting to the transmission system and/or the provision of transmission service. This proceeding is not intended to disrupt existing commercial arrangements, but rather to establish prospective reforms. Accordingly, any Tariff revisions offered by PJM and/or the Transmission Owners in response to this proceeding should (a) propose a reasonable implementation period to ensure minimal disruption to such existing commercial arrangements, and (b) allow a reasonable amount of time to finalize ongoing agreements that are nearing completion as of the date such Tariff provisions are filed with the Commission. Such proposed Tariff revisions should include a reasonable effective date that accommodates such considerations regarding these existing commercial arrangements.

willing and able to limit their energy withdrawals from the transmission system under certain conditions. *See infra* note 178.

¹⁶ *Cf.* PJM Co-Location Order, 193 FERC ¶ 61,217 at PP 237-239 (highlighting PJM's ongoing Critical Issue Fast Path stakeholder process to consider proposals to help integrate large load additions without causing resource inadequacy and directing an informational report on the status of those proposals).

I. Background

A. Growth of Large and Co-Located Loads and ANOPR

6. As the Secretary explained in the ANOPR, electricity demand in the United States is expected to grow at an extraordinary pace in the near term, largely due to the rapid growth of large loads.¹⁷ The Secretary highlighted findings from the North American Electric Reliability Corporation (NERC) that show that demand growth is now higher than at any point in the past two decades, driven in part by increasing quantities of large commercial and industrial load, most notably data centers, connecting rapidly to the transmission system.¹⁸ The Secretary also highlighted NERC's conclusion that the size and speed with which data centers can be connected to the grid present unique challenges for demand forecasting and system planning. The ANOPR proposed that, in light of the unprecedented current and expected growth of large loads seeking to interconnect to the transmission system, the Commission should standardize interconnection procedures and agreements for large loads, including those that seek to share a point of interconnection with new or existing generation facilities.¹⁹

7. On April 16, 2026, the Commission issued an order regarding its intent to act with respect to the ANOPR docket.²⁰ In that order, the Commission explained that it agreed with the Secretary "that, '[i]n light of the unprecedented current and expected growth of large loads' such as data centers, there is an urgent need for thoughtful reforms to ensure that large loads are 'able to connect to the transmission system in a timely, orderly, and

¹⁷ ANOPR at 2 (citing U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability & Security of the United States Electric Grid* (July 2025), www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf).

¹⁸ *Id.* (citing NERC, *2024 Long-Term Reliability Assessment* 8 (Dec. 2024, updated July 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

¹⁹ *Id.* P 12. For example, the ANOPR proposed that load and hybrid facilities should be studied together with generating facilities, observing that "siting a large load near or at the same point of interconnection as a new generating facility could reduce the network upgrades needed to interconnect only the load or only the generating facility." ANOPR at P 20.

²⁰ *Interconnection of Large Loads to the Interstate Transmission Sys.*, 195 FERC ¶ 61,045 (2026) (Order Regarding Intent to Act).

non-discriminatory manner.”²¹ After recognizing the Commission’s recent actions in proceedings involving issues associated with large loads,²² the Commission concluded that it was clear that additional “action is warranted to support further progress where it is needed.”²³

8. PJM’s load forecast predicts peak load growth of 32 gigawatts (GW) from 2024 to 2030, 30 GW of which is projected to be from data centers.²⁴ Many commenters in the ANOPR proceeding highlight the unprecedented load growth in PJM associated with large loads. For example, AES Ohio currently forecasts over 6.3 GW of new load by 2032, which will nearly triple AES Ohio’s current peak.²⁵ Exelon states that, in ComEd’s service territory, data center demand has grown at an annual rate of 27% through June 2025, and ComEd’s most recent large load adjustment request to PJM included a future expected demand increase of 11 GW by 2040, 6 GW higher than ComEd’s submission relative to the prior year.²⁶ WATT and Advancing Modern Powerlines note that PJM is expected to host as much as 70% of future U.S. data center development and that this concentration of demand, especially in northern Virginia’s “data center alley,” is creating intense pressure for new greenfield transmission to support the interconnection

²¹ *Id.* P 2.

²² *Id.* (citing PJM Co-Location Order, 193 FERC ¶ 61,217; SPP HILL Order, 194 FERC ¶ 61,031; *Commonwealth Edison Co.*, 194 FERC ¶ 61,181; *Tri-State Generation & Transmission Ass’n*, 193 FERC ¶ 61,070 (2025); *Duke Energy Carolinas, LLC*, 193 FERC ¶ 61,237).

²³ *Id.* PP 3-4.

²⁴ Letter from David E. Mills, PJM Board of Managers Chair, PJM, Interconnection, L.L.C. to PJM Stakeholders (Aug. 8, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf> (PJM Board Letter). Since the issuance of the PJM Board Letter, PJM has published its 2026 Long-Term Load Forecast Report, which anticipates lower peak demand in the near term due to forecasting improvements, revising the peak load forecast for 2030 downward by 875 MW, but confirms significant growth in the next 20 years. PJM, *PJM’s Updated 20-Year Forecast Continues to See Significant Long-Term Load Growth* (Jan. 14, 2026), <https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/>.

²⁵ AES November 21 ANOPR Comments at 4.

²⁶ Exelon November 21 ANOPR Comments at 2.

of data centers.²⁷ Buckeye states that load growth of approximately 10 GW driven largely by data centers in the Dominion Zone of PJM resulted in approximately \$12 billion in transmission investment across PJM.²⁸

9. A number of commenters in the ANOPR proceeding assert that large load additions have caused growing resource adequacy, reliability, and affordability problems in PJM.²⁹ Commenters also argue that large load interconnection in PJM is experiencing significant delays.³⁰ In addition, Buckeye and Southeast PIOs express concern that infrastructure costs driven by data center loads will be borne by all transmission customers in the corresponding PJM transmission zones and, where applicable, in the broader PJM region.³¹ They and other commenters argue that wholesale transmission customers are at risk of absorbing cost shifts and that retail large load tariffs do not protect wholesale transmission customers from cost shifting.³² Vistra also raises concerns that PJM and transmission owners' processes for determining Network

²⁷ WATT and Advancing Modern Powerlines November 21 ANOPR Comments at 4.

²⁸ Buckeye November 21 ANOPR Comments at 6.

²⁹ *See, e.g.*, ECA November 21 ANOPR Comments at 8; Geronimo November 21 ANOPR Comments at 7; Illinois AG November 21 ANOPR Comments at 5-6; Joint Consumer Advocates November 21 ANOPR Comments at 2; OCC November 21 ANOPR Comments at 6-7; PIOs November 21 ANOPR Comments at 3-5, 13-14; PJM IMM November 25 ANOPR Comments, Attach. A at 3-5.

³⁰ International Energy Credit Association November 21 ANOPR Comments at 6; Constellation November 21 ANOPR Comments at 2, 49-51.

³¹ *See, e.g.*, Buckeye November 21 ANOPR Comments at 8; Southeast PIOs November 21 ANOPR Comments at 10-11 (asserting that there is a significant overlap between multi-driver projects that may be driven by increased loads, including data centers, and those transmission projects selected in PJM's recent RTEP solicitation).

³² *See, e.g.*, APPA November 21 ANOPR Comments at 6 ("Wholesale transmission customers in particular could be left shouldering massive costs if new large loads do not ultimately attain or maintain the level of electricity demand that is being forecasted."); NRECA November 21 ANOPR Comments at 21 (noting the risk that other transmission customers could bear stranded upgrade costs caused by large loads that they cannot absorb); TAPS November 21 ANOPR Comments at 26 ("[A] number of state commissions are moving forward with retail large load tariffs, which provide for varying protections, but may not require the revenues and minimum demand levels to be included in wholesale transmission rates.").

Upgrades are not included in the Tariff and that existing transmission customers may be disproportionately shouldering the costs for interconnecting large loads.³³ OCC requests that the Commission provide additional transparency regarding large load additions.³⁴ Commenters also support reforms to capture the efficiencies of generation paired with electrically proximate large load.³⁵

10. Moreover, many commenters in the ANOPR proceeding filed persuasive comments documenting, generally, the need for clear and consistent tariff provisions to ensure regulatory and process certainty, fairness and consistency, and efficiency as large loads are added to the transmission system in increasing numbers.³⁶ There is also broad support for rules that help to ensure that other transmission customers are not unfairly burdened with additional costs or reliability impacts as large loads interconnect to the transmission system.³⁷ In addition, many ANOPR commenters highlighted the need to

³³ Vistra November 21 ANOPR Comments at 22-23.

³⁴ OCC November 21 ANOPR Comments at 3-4.

³⁵ *See, e.g.*, AEP December 5 ANOPR Comments at 10-12; Exelon November 21 ANOPR Comments at 14; Illinois AG November 21 ANOPR Comments at 8.

³⁶ *See, e.g.*, AI Supply Chain Alliance November 21 ANOPR Comments at 2; Calibrant November 21 ANOPR Comments at 1-3; CEBA November 21 ANOPR Comments at 9-11; Constellation November 21 ANOPR Comments at 6; DCC November 21 ANOPR Comments at 3-4; ECA November 21 ANOPR Comments at 7-11; EPSA November 21 ANOPR Comments at 4-6; Infrastructure Masons December 5 ANOPR Comments at 4-7; Microsoft November 21 ANOPR Comments at 9-10; National Grid November 21 ANOPR Comments at 7; ODEC December 5 ANOPR Comments at 2-4; R Street November 21 ANOPR Comments at 3; Switch December 5 ANOPR Comments at 3; Tract November 21 ANOPR Comments at 5; Vantage November 21 ANOPR Comments at 5-6; Vistra December 5 ANOPR Comments at 1-2.

³⁷ *See, e.g.*, APPA November 21 ANOPR Comments at 6; Buckeye November 21 ANOPR Comments at 17; Exelon November 21 ANOPR Comments at 10; Kansas Commission November 21 ANOPR Comments at 12; NCSL November 21 ANOPR Comments at 1; NRECA November 21 ANOPR Comments at 8-9; NY UIU November 21 ANOPR Comments at 3; OCC November 21 ANOPR Comments at 9; Oklo December 5 ANOPR Comments at 3; Southeast PIOs December 5 ANOPR Comments 11-15; State Entities November 21 ANOPR Comments at 7-8; Tri-State November 21 ANOPR Comments at 8; UCS November 21 ANOPR Comments at 9-11; U.S. Representatives November 21 ANOPR Comments at 1.

efficiently integrate large loads, particularly data centers, to support national security priorities and economic development.³⁸

B. Recent Proceedings Addressing Large and Co-Located Loads

11. Over the past year, the Commission has begun to address, both *sua sponte* and in response to complaints and FPA section 205³⁹ filings, the growing use of co-location arrangements.⁴⁰ The Commission's orders in those proceedings have addressed the need for clear and consistent tariff provisions regarding the rates, terms, and conditions of service that apply to co-location arrangements and for transmission services that reflect Eligible Customers taking transmission service on behalf of co-located loads and load with behind the meter generation that are willing and able to limit their energy withdrawals from the transmission system under certain conditions. Several other Commission proceedings have addressed the challenges of integrating large loads onto the transmission system, including the need for clear and consistent tariff provisions regarding the provision of transmission service to Eligible Customers on behalf of large loads and for interconnection customers serving electrically proximate large load. As explained below, these proceedings provide examples that will help to ensure that jurisdictional transmission service is provided in a manner that is just and reasonable and maintains reliability as large loads are integrated onto the transmission system and co-location arrangements become more common. It is in this context, and in recognition of the steps PJM has taken with respect to co-location arrangements, that the Commission now considers whether PJM's Tariff remains just and reasonable.

1. PJM Co-Location Proceedings

12. On February 20, 2025, the Commission initiated a show cause proceeding against PJM and the PJM Transmission Owners regarding the lack of tariff provisions addressing with sufficient clarity or consistency the rates, terms, and conditions of service that apply

³⁸ See, e.g., AI Supply Chain Alliance November 21 ANOPR Comments at 2; DCC November 21 ANOPR Comments at 3; ECA November 21 ANOPR Comments at 6; Geronimo November 21 ANOPR Comments at 1-2; Google November 21 ANOPR Comments at 2-3; Verrus December 5 ANOPR Comments at 2.

³⁹ 16 U.S.C. § 824d.

⁴⁰ See PJM Show Cause Order, 190 FERC ¶ 61,115; PJM Co-Location Order, 193 FERC ¶ 61,217, *order on reh'g*, PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209; SPP HILL Order, 194 FERC ¶ 61,031; SPP CHILLS Order, 195 FERC ¶ 61,196.

to co-location arrangements.⁴¹ The Commission explained when initiating that proceeding that the absence of such provisions may leave entities unable to determine what steps they can or must take to effectuate co-location arrangements of various configurations and how to do so in a manner that is just and reasonable.⁴² On December 18, 2025, the Commission found that PJM's Tariff was indeed unjust and unreasonable because it does not contain provisions addressing with sufficient clarity or consistency the rates, terms, and conditions of service that apply to interconnection customers serving co-located load and Eligible Customers taking transmission service on behalf of co-located load.⁴³

13. Specifically, the Commission found that the PJM Tariff was unjust and unreasonable because there is a lack of sufficient clarity or consistency as to the rates, terms, and conditions of service that apply to interconnection customers serving co-located load.⁴⁴ The Commission also found that PJM's Tariff was unjust and unreasonable because it does not include transmission services that reflect Eligible Customers taking transmission service on behalf of co-located loads that are willing and able to limit their energy withdrawals from the transmission system under certain conditions.⁴⁵ Additionally, the Commission found that PJM's behind the meter generation rules were no longer just and reasonable.⁴⁶ The Commission directed PJM to file a compliance filing to revise its Tariff: (1) to set forth specific terms and conditions that an interconnection customer in PJM seeking to serve co-located load must follow in order to effectuate a co-location arrangement;⁴⁷ (2) to require that the Eligible Customer taking transmission service on behalf of co-located load takes one of three transmission services: (a) network integration transmission service (NITS) or a new interim, non-firm transmission service while Network Upgrades to provide full NITS service are

⁴¹ See PJM Show Cause Order, 190 FERC ¶ 61,115.

⁴² *Id.* P 74. The PJM Show Cause Order defined co-located load as a “configuration [that] refers to end-use customer load that is physically connected to the facilities of an existing or planned Customer Facility on the Interconnection Customer's side of the Point of Interconnection (‘POI’) to the PJM Transmission System.” *Id.* P 3 n.4.

⁴³ PJM Co-Location Order, 193 FERC ¶ 61,217.

⁴⁴ *Id.* P 176.

⁴⁵ *Id.* P 177.

⁴⁶ *Id.* P 179.

⁴⁷ *Id.* PP 187-192, 225-230.

constructed (interim NITS); (b) a new firm contract demand transmission service; or (c) a new non-firm contract demand transmission service;⁴⁸ (3) to revise the behind the meter generation rules and implement a transition process for existing behind the meter generation participants;⁴⁹ and (4) to make several clarifications on how certain aspects of PJM's generator interconnection process apply to interconnection customers seeking to serve co-located load.⁵⁰

14. On June 18, 2026, concurrently with the instant order, the Commission issued an order modifying the discussion in the PJM Co-Location Order and setting aside the order in part; accepting in part and rejecting in part PJM's compliance filing, and directing a further compliance filing; and establishing as just and reasonable certain rates, terms, and conditions for the new transmission services (i.e., interim NITS, firm contract demand transmission service, and non-firm contract demand transmission service).⁵¹

2. SPP High Impact Large Load Process and High Impact Large Load Generation Assessment Processes

15. On January 14, 2026, the Commission accepted revisions to SPP's tariff to add a high impact large load (HILL) study process and High Impact Large Load Generation Assessment (HILLGA) process.⁵² SPP's tariff revisions established HILLs as a new category of load;⁵³ imposed enhanced study requirements to enable SPP to assess the

⁴⁸ *Id.* PP 193-218. The Commission also established a paper hearing to determine the just and reasonable rates, terms, and conditions for the new transmission services. *Id.* PP 219-220.

⁴⁹ *Id.* PP 221-224.

⁵⁰ *Id.* PP 161, 231-236.

⁵¹ PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209 at PP 7-9. PJM's compliance filing proposing revisions in response to the Commission's directives regarding clarification that certain aspects of PJM's generator interconnection process apply to interconnection customers seeking to serve co-located load was accepted in part on April 16, 2026. *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,030 (2026).

⁵² SPP HILL Order, 194 FERC ¶ 61,031 at PP 61, 64.

⁵³ SPP defines a HILL as:

A new commercial or industrial load, or increase in commercial or industrial load, at a single site connected through one or more shared Points of Interconnection (POIs) or delivery points, where such load is either: (1) 10 MW or

HILL's reliability impacts on the transmission system;⁵⁴ and created additional, ongoing operational requirements for transmission customers serving HILLs to ensure continued reliability of the transmission system.⁵⁵ The tariff revisions also established the HILLGA process, a new generator interconnection service and related interconnection process to facilitate the prompt interconnection of generating facilities that are specifically identified for, and limited to, serving a HILL and are located no more than two substations away from the HILL.⁵⁶

more if connected to the Transmission System at a voltage level less than or equal to 69 [kilovolts (kV)]; or (2) 50 MW or more if connected to the Transmission System at a voltage level greater than 69 kV. An Electric Storage Resource is not considered a HILL.

SPP, Open Access Transmission Tariff, Sixth Revised Vol. No. 1, pt. I, § 1 (Definitions H) (1.0.0).

⁵⁴ SPP HILL Order, 194 FERC ¶ 61,031 at PP 13-17 (explaining that the HILL process requires up to three additional studies beyond those required of all transmission service requests for transmission customers requesting to add or modify a delivery point associated with a HILL, including a HILL delivery point study, HILL supplemental load connection study, and potential supplemental Electromagnetic Transient study).

⁵⁵ *Id.* P 18 (explaining that market participants registering a HILL must: (1) follow all nonconforming load requirements (e.g., additional load forecast requirements); (2) provide load data via telemetry in real time; (3) have remote capability to disconnect the load from the transmission system made available to the transmission operator; (4) have an up/down ramp rate not exceeding 20 MW per minute unless otherwise directed; (5) include additional information with registration; and (6) not have withdrawals from the transmission system without appropriate transmission service); *id.* P 19 (explaining that the transmission owner, at the transmission customer's expense, must install a phasor measurement unit or similar equipment); *id.* PP 20-21 (explaining that the transmission customer will be required to comply with ride-through requirement guidelines).

⁵⁶ *Id.* P 27 (explaining that, under the HILLGA process, SPP proposes to study HILLGA requests to determine whether any network upgrades are needed to accommodate the generating facility's injection to the local area); *id.* P 32 (explaining that SPP will grant HILLGA customers a new type of interconnection service, load limited resource interconnection service, which grants limited interconnection service solely to serve the associated HILL).

16. The Commission stated that SPP demonstrated that the “unprecedented growth in large loads in the SPP region presents significant and unique operational and planning challenges.”⁵⁷ The Commission found that SPP demonstrated that its proposed HILL process was a just and reasonable approach for integrating transmission customers’ new large loads onto SPP’s transmission system in a reliable manner.⁵⁸ The Commission found that it was reasonable to impose additional study requirements and other proposed requirements given the unique operating characteristics of HILLs. The Commission further found that the proposed study requirements would ensure the reliable integration of the transmission customer’s HILLs onto SPP’s transmission system and would provide SPP with information about their impact on SPP’s transmission system, including the transmission system’s ability to withstand and control disturbances by the HILL at the point of interconnection.⁵⁹ In addition, the Commission found that the proposed study deposits would discourage speculative HILL study requests.⁶⁰ Finally, the Commission concluded that the proposed ongoing reliability requirements would allow SPP to maintain reliable operation of its transmission system by increasing SPP’s visibility, providing necessary data, and imposing real-time operational safeguards for HILLs.⁶¹ In accepting HILLGA, the Commission found that “SPP’s HILLGA process reasonably provides a flexible, expedited, and separate serial interconnection process that will facilitate the prompt interconnection of generating facilities that are limited to serving a HILL in the same local area.”⁶²

3. SPP Conditional High Impact Large Load Service

17. On June 5, 2026, the Commission accepted revisions to SPP’s tariff to add a new type of non-firm transmission service, conditional high impact large load service

⁵⁷ *Id.* P 60.

⁵⁸ *Id.* P 61.

⁵⁹ *Id.* P 62.

⁶⁰ For the HILL delivery point study, SPP required a \$10,000 non-refundable application fee and a \$100,000 study deposit, with an additional \$200,000 study deposit if an Electromagnetic Transient study was also required. *Id.* P 15. For the HILL supplemental load connection study, SPP allows the host transmission owner to require a \$25,000 study deposit. *Id.* P 16.

⁶¹ *Id.* P 63.

⁶² *Id.* P 64.

(CHILLS).⁶³ CHILLS allows transmission customers serving HILLs to reliably receive transfers of energy until sufficient designated resources and/or network upgrades are in place to support long-term, firm transmission service.⁶⁴ CHILLS is an as-available transmission service that will transfer energy to designated points of delivery to serve the portion of a HILL eligible to receive CHILLS, subject to curtailment and interruption.⁶⁵ CHILLS has a maximum term of seven years, which is intended to incentivize transmission customers seeking CHILLS to obtain the designated resources and/or complete the network upgrades needed to procure long-term firm transmission service through existing tariff processes.⁶⁶

18. The Commission found that SPP had shown that unprecedented growth in large loads presents significant and unique operational and planning challenges.⁶⁷ The Commission also found that SPP's ability to add HILLs to its transmission system in a timely manner may be limited due to delays in obtaining sufficient designated resources and completing network upgrades needed to provide long-term firm transmission service to such load.⁶⁸ The Commission concluded that CHILLS is a just and reasonable and not unduly discriminatory or preferential approach to addressing the need to expeditiously interconnect and provide transmission service to new HILLs, while maintaining the reliable operation of SPP's transmission system.⁶⁹

II. PJM's Existing Processes

A. Existing Tariff Processes

19. PJM's Tariff sets forth a process by which an Eligible Customer may request either NITS,⁷⁰ including modifications to existing service agreements to add new

⁶³ SPP CHILLS Order, 195 FERC ¶ 61,196 at P 1.

⁶⁴ *Id.* P 7.

⁶⁵ *Id.* PP 9-10.

⁶⁶ *Id.* P 9.

⁶⁷ *Id.* P 84.

⁶⁸ *Id.*

⁶⁹ *Id.*

⁷⁰ NITS is a transmission service that allows Network Customers to use their Network Resources (as well as other non-designated generation resources) to serve their

Network Loads, or Point-to-Point Transmission Service.⁷¹ In the PJM Co-Location Order, the Commission also directed PJM to create three new transmission services that an Eligible Customer taking transmission service on behalf of co-located load may take: (1) an interim, non-firm transmission service until all Network Upgrades necessary to provide the requested NITS are complete, (2) a new Firm Contract Demand transmission service, and (3) a new Non-Firm Contract Demand transmission service.⁷²

20. In PJM, new load additions are processed in one of two ways: (1) an Eligible Customer requesting new transmission service submits a Transmission Service Request to PJM; or (2) for existing Network Customers adding new Network Loads, the Network Customer provides PJM with notice of the designation of new Network Load and must modify its existing service agreement accordingly.⁷³ For NITS and Firm Point-to-Point Transmission Service Requests, PJM determines whether a Phase I System Impact Study⁷⁴ is needed to assess whether the transmission system has sufficient available capability to provide the requested service and tenders an Application and Studies

Network Load located in the PJM region and designated additional loads. PJM Tariff, pt. III, § 28.1 (Scope of Service) (1.0.0).

⁷¹ Point-to-Point Transmission Service provides for “the reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.” *Id.* pt. I, § 1 (Definitions O-P-Q) (36.0.0) (definition of Point-to-Point Transmission Service).

⁷² PJM Co-Location Order, 193 FERC ¶ 61,217 at P 160.

⁷³ PJM Tariff, pt. III, § 31.2 (New Network Loads Connected With the Transmission Provider) (1.0.0). To the extent that a Network Customer seeks to add a new Delivery Point or interconnection point between the PJM transmission system and a Network Load, the Network Customer must provide PJM with as much advance notice as reasonably practicable. *Id.* pt. III, § 31.4 (New Interconnection Points) (0.0.0).

⁷⁴ PJM’s study process for New Service Requests consists of Phase I, II, and III System Impact Studies.

Agreement⁷⁵ to initiate a New Service Request pursuant to which the Eligible Customer agrees to reimburse PJM for the required Phase I System Impact Study.⁷⁶

21. PJM studies all New Service Requests including generator interconnection requests, merchant transmission interconnection requests, and long-term firm transmission service requests⁷⁷ in a single queue (New Services Queue), which is governed by the transitional interconnection process in Part VII of the Tariff (for requests submitted between April 1, 2018 and September 30, 2021, where an Interconnection Customer does not have an Interconnection Service Agreement as of July 10, 2023), and the new cycle interconnection process in Part VIII of the Tariff (“new rules” for valid New Service Requests submitted on or after October 1, 2021).⁷⁸ PJM’s New Services

⁷⁵ PJM’s Tariff defines an “Application and Studies Agreement” as the application that must be submitted by a Project Developer or Eligible Customer that seeks to initiate a New Service Request. PJM Tariff, pt. VII, § 300 (Definitions A) (3.0.0); *id.* pt. VIII, § 400 (Definitions A) (2.0.0).

⁷⁶ *Id.* pt. III, § 32.1 (Notice of Need for Phase I System Impact Study) (2.0.0); *id.* pt. II, § 19.1 (Notice of Need for Phase I System Impact Study) (4.0.0). As the RTO, PJM administers the interconnection of generating facilities and Merchant Transmission Facilities, requests for transmission service, and upgrades to existing transmission owner facilities in the PJM transmission system through the New Service Requests process. PJM Manual 14H: New Service Requests Cycle Process, § 1.1 (Sep. 2025), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.ashx> (PJM Manual 14H).

⁷⁷ *Id.* pt. VII, subpt. C, § 306(A)(3) (Application Rules) (1.1.0) (includes specific additional application requirements for Long-Term Firm Transmission Service seeking to initiate a New Services Request); *id.* pt. VIII, subpt. B § 403(A)(3) (Application Rules) (0.1.0); *id.*, pt. VII, § 300 (Definitions N) (2.0.0) (definition of New Service Request); *id.* pt. VIII, § 400 (Definitions N) (2.0.0) (definition of New Service Request); *see also id.* pt. VII, § 300 (Definitions C) (2.0.0) (definition of Completed Application); *id.* pt. VII, § 300 (Definitions I) (2.0.0) (definition of Interconnection Request); *id.* pt. VIII, § 400 (Definitions C) (2.0.0) (definition of Completed Application); *id.* pt. VIII, § 400 (Definitions I) (2.0.0) (definition of Interconnection Request); *id.* pt. I, § 1 (Definitions A-B) (19.1.1) (definition of Application).

⁷⁸ *See id.* pt. VII, § 301 (Transition Introduction) (1.0.0) (“Part VII sets forth the procedures and other terms governing the Transmission Provider’s administration of the transition to the new Cycle-process, including procedures and other terms regarding studies and other processing of New Service Requests within the Transition Cycle”); *id.* pt. VIII, § 401 (Applications for Cycle Process Intro) (2.0.0); *id.* pt. VIII, § 401(A) (New Cycle Process) (2.0.0) (“Part VIII of the Tariff applies to valid New Service Requests

Queue is a first-ready, first-served clustered cycle approach that consists of an application phase, a three-phase study process, where each phase includes a System Impact Study and decision point, and a final agreement negotiation phase. For transmission service requests, once the New Service Request is processed, the transmission customer will enter into a transmission service agreement, a construction service agreement, and/or a Network Upgrade cost responsibility agreement. PJM's Tariff does not have any specific study provisions or requirements for Eligible Customers requesting transmission service on behalf of large load additions.

22. The system impact study is an assessment by PJM of: (1) the adequacy of the transmission system to accommodate a New Service Request; (2) whether any additional costs may be incurred in order to provide such transmission service or to accommodate a New Service Request; and (3) an estimated date that the New Service Requests can be interconnection with the transmission system and an estimate of the cost responsibility for the interconnection of the New Service Request.⁷⁹ The System Impact Studies also provide "estimates of cost responsibility and construction lead time for new facilities required to interconnect the project and required system upgrades,"⁸⁰ including Network Upgrades. The Tariff describes the phases and studies that determine the cost allocation of Network Upgrades to New Service Requests, and PJM Manual 14H provides the implementation details used to govern the interconnection and transmission customers service request process for new generating facilities seeking to connect to or use the PJM transmission system through PJM's cluster-based queue methodology.⁸¹ Specifically, the

submitted on or after October 1, 2021, and sets forth the . . . procedures and other terms regarding studies and other processing of New Service Requests"); *id.* pt. VIII, § 401(B) (Applications for Cycle Process) (2.0.0) ("Part VIII of the Tariff applies to (a) Generation Interconnection Requests; (b) Transmission Interconnection Requests; and (c) Completed Applications").

⁷⁹ *Id.* pt. VIII, § 400 (Definitions S) (3.0.0) (definition of System Impact Study). The System Impact Study includes facilities study analysis.

⁸⁰ *Id.* pt. VII, subpt. D, § 307 (Introduction) (1.0.0); *id.* pt. VII, subpt. D, § 307(A)(2)(a)(ii) (Overview of System Impact Studies) (1.0.0); *id.* pt. VIII, subpt. C, § 404 (Introduction) (1.0.0); *id.* pt. VIII, subpt. C, § 404(2)(a)(ii) (Introduction) (1.0.0).

⁸¹ *See id.* pt. VII, subpt. D § 307 (Introduction) (1.0.0) (including a description of the phases and an overview of the System Impact Studies and cost allocation of Network Upgrades, noting that the cost allocation will be in accordance with PJM Manuals); *id.* pt. VII, subpt. D § 307(A)(5)(c) (Cost Allocation for Network Upgrades) (1.0.0); *id.* pt. VIII, subpt. C, § 404 (Introduction) (1.0.0), *id.* pt. VIII, subpt. C, § 404(A)(5)(c) (Cost Allocation for Network Upgrades) (1.0.0); *see* PJM Manual 14H: New Service Requests

Tariff provides that each “Eligible Customer shall be obligated to pay for 100% of the costs of the minimum amount of Network Upgrades necessary to accommodate its New Service Request and that would not have been incurred under the Regional Transmission Expansion Plan [(RTEP)] but for such New Service Request, net of benefits resulting from the construction of the upgrades, such costs not to be less than zero.”⁸² The Tariff further specifies that “[a]ll New Service Requests that contribute to the need for a Network Upgrade will receive cost allocation for that upgrade pursuant to each New Service Request’s contribution to the reliability violation identified on the transmission system in accordance with PJM Manuals.”⁸³

23. As relevant on the generator interconnection side, pursuant to the Tariff, a Project Developer may request, and PJM may provide, Provisional Interconnection Service for limited interconnection service at the discretion of PJM based upon an evaluation that will consider the results of available studies.⁸⁴ PJM determines, through available studies or additional studies as necessary, “whether stability, short circuit, thermal, and/or voltage issues would arise” if the Project Developer interconnects without modifications to the Generating Facility or the transmission system.⁸⁵ Under the Tariff, a Project Developer may also request surplus interconnection service for an unneeded portion of interconnection service capacity at an existing point of interconnection.⁸⁶ The surplus interconnection study consists of reactive power, short circuit/fault duty, stability analysis and any other appropriate analyses, and steady-state (thermal/voltage) analyses may be

Cycle Process, § 4.2.6 (Sep. 2025), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.ashx> (PJM Manual 14H).

⁸² PJM Tariff, pt. VII, subpt. D, § 307(A)(5)(a) (Cost Allocation for Network Upgrades) (1.0.0); *id.* pt. VIII, subpt. C, § 404 (A)(5)(a) (Cost Allocation for Network Upgrades) (1.0.0).

⁸³ *Id.* pt. VII, subpt. D, § 307(A)(5)(c) (Cost Allocation for Network Upgrades) (1.0.0); *id.* pt. VIII, subpt. C, § 404 (A)(5)(c) (Cost Allocation for Network Upgrades) (1.0.0).

⁸⁴ *Id.* pt. IX, subpt. B, app. 2, § 1.4A.2 (Provisional Interconnection Service) (0.0.0).

⁸⁵ *Id.*

⁸⁶ *Id.* pt. VIII, subpt. E, § 414(A) (Surplus Interconnection Service Request) (1.0.0).

performed as necessary to ensure that all required reliability conditions are studied under off-peak conditions.⁸⁷

24. In PJM, electric distribution companies and transmission owners administer load interconnection processes for existing Network Customers, and transmission owners perform local transmission planning to accommodate load additions.⁸⁸ PJM, as transmission provider, conducts additional studies and transmission planning activities to support load additions. Requests to physically interconnect loads are submitted to transmission owners, who have their own study processes and requirements. Some transmission owners have established specific large load interconnection procedures and requirements.⁸⁹ New loads taking bundled retail service from a transmission owner or that are served subject to state-required retail access programs (Native Load) are studied through transmission owners' local transmission planning processes. Transmission owners must designate resources and loads to serve Native Load in the same manner as any Eligible Customer.⁹⁰

25. Network Upgrades identified in transmission owners' local transmission planning process as needed to accommodate load additions are designated as Supplemental Projects under Attachment M-3 of PJM's Tariff.⁹¹ Under Attachment M-3, transmission owners plan for the local transmission needs of their own transmission systems. Attachment M-3 provides procedures for stakeholder review and comment on Supplemental Projects in the Transmission Expansion Advisory Committee (230 kV or above) and Subregional RTEP Committee (below 230 kV) and as part of a transmission

⁸⁷ *Id.* pt. VIII, subpt. E, § 414(B)(1) (Surplus Interconnection Study) (1.0.0).

⁸⁸ *See* PJM November 21 ANOPR Comments at 6.

⁸⁹ *See, e.g.*, EEI March 12 ANOPR Comments at 13 ("In December 2025, Exelon subsidiary Delmarva Power submitted proposed changes in line with the Commission's November 2025 order: a new service class 'GS-LD' applicable to large demand customers with a monthly maximum of 25 MW or greater. The company also proposed implementing an application process and specific requirements for potential customers with a projected load of at least 50 MW."); *id.* ("Exelon subsidiary Commonwealth Edison Company (ComEd) has proposed revisions to Rider DE that clarify requirements and procedures for large load customers' new service requests.").

⁹⁰ PJM Tariff, pt. III, § 28.2 (Transmission Provider Responsibilities) (1.0.0).

⁹¹ *See id.* attach. M-3 (Additional Procedures for Planning Supplemental Projects and Asset Management Projects) (1.0.0).

owner's Local Plan, before the Local Plan is submitted for integration into the RTEP.⁹² These transmission projects do not qualify for region-wide cost allocation, and PJM conducts only a "do no harm" test to ensure that local transmission facilities do not adversely impact the reliability of the broader transmission system before the Supplemental Projects are added into the RTEP base case.⁹³ Supplemental Project costs are allocated to the local transmission owner's zone pursuant to individual transmission owner cost allocation frameworks.⁹⁴

26. Attachment H of the PJM Tariff includes the formula rate for each transmission owner. The formula rate calculates the annual transmission revenue requirement, and resulting NITS rate, in the relevant PJM transmission zones. The demand charges for NITS, which are charged to the relevant Network Customer (i.e., the Eligible Customer), are determined by multiplying the rate for NITS (based on the NITS rate in Attachment H of the relevant transmission zone) by the customer's coincident peak demand.⁹⁵

27. In some instances, an aggregation of large loads, coupled with other drivers, could trigger regional (as opposed to local) transmission system needs, which would be identified and addressed by a regional transmission project in the RTEP, which is subject to PJM's regional cost allocation method. For example, a transmission owner may identify a local transmission need that may be more efficiently or cost-effectively addressed by a regional transmission project identified in the RTEP.⁹⁶

28. The Tariff includes a hybrid cost allocation method that was accepted as part of PJM's compliance with Order No. 1000 for Regional Facilities and Necessary Lower Voltage Facilities that address a reliability need.⁹⁷ Under this method, PJM allocates

⁹² See *id.* § (c) (Procedures for Review of Attachment M-3 Projects).

⁹³ See PJM Interconnection, L.L.C., Answer, Docket No. EL25-49-000, at 6-7 (filed Mar. 24, 2025); PJM Manual 14B: PJM Regional Transmission Planning Process, § 1.1 (Apr. 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf#page=14>.

⁹⁴ PJM Interconnection, L.L.C., Answer, Docket No. EL25-49-000, at 7 (filed Mar. 24, 2025).

⁹⁵ PJM Tariff, pt. III, § 34.1 (Monthly Demand Charge) (1.0.0).

⁹⁶ See, e.g., *Potomac Edison Co.*, 190 FERC ¶ 61,074, at PP 5, 22 (2025) (allowing for recovery of abandoned plant costs where a local transmission project was superseded by regional transmission development in PJM's RTEP process).

⁹⁷ PJM identifies reliability transmission needs and economic constraints that result from the incorporation of public policy requirements into its sensitivity analyses

50% of the costs of Regional Facilities or Necessary Lower Voltage Facilities on a load-ratio share basis and the other 50% based on the solution-based distribution factor (DFAX) method. PJM allocates all of the costs of Lower Voltage Facilities using the solution-based DFAX method. Cost responsibility assignments pursuant to the Order No. 1000-compliant cost allocation method are included in Schedule 12-Appendix A of the Tariff.

29. Schedule 12 of the Tariff provides that cost responsibility for the portion of costs allocated on a load-ratio share basis will be updated annually using the applicable zonal loads at the time of each zone's annual peak load from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility assignment is determined, consistent with section 34.1 of the Tariff.⁹⁸

30. Schedule 12 of the Tariff also provides that, for the portion of cost responsibility assignments allocated pursuant to the solution-based DFAX method, PJM shall make a preliminary cost responsibility assignment for each Required Transmission Enhancement at the time such transmission facility is selected in the RTEP for purposes of cost allocation. Further, beginning with the calendar year in which a transmission facility is scheduled to enter service, and thereafter annually at the beginning of each calendar year, PJM shall update the preliminary cost responsibility assignment for each transmission facility using the values and inputs used in the base case of the most recent RTEP approved by the PJM Board prior to the date of the update.⁹⁹

B. Recent Stakeholder Proceedings in PJM

31. PJM has begun considering reforms to address large load additions, including the development of solutions to ensure large load additions can continue to be integrated

and allocates the costs of the solutions to such transmission needs in accordance with the type of benefits they provide. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 441 (2013); *see* PJM Tariff, Schedule 12 (15.0.0), § (b)(v) (assigning cost responsibility for Economic Projects that are either accelerations or modifications of Reliability Projects, or new enhancements or expansions that relieve one or more economic constraints); PJM, Intra-PJM Tariffs, Operating Agreement, Schedule 6, § 1.5 (Procedure for Development of the Regional Transmission Expansion Plan) (29.1.0), 1.5.7(c)(iii).

⁹⁸ PJM Tariff, Schedule 12, § (b)(i)(A)(1) (Designation of Customers Subject to Transmission Enhancement Charges) (15.0.0).

⁹⁹ *Id.* § (b)(iii)(H)(2) (Designation of Customers Subject to Transmission Enhancement Charges) (15.0.0). The annual update includes any projects that were included to address any individual transmission owner Form No. 715 local planning criteria.

rapidly and reliably without causing resource inadequacy. On January 16, 2026, the PJM Board issued a decisional letter on the Critical Issues Fast Path (CIFP) detailing the initiatives that PJM will move forward to implement, which include: (1) a definition for large load additions; (2) load forecasting improvements; (3) voluntary “Bring Your Own New Generation” commensurate with large load additions; (4) an expedited generator interconnection track to offset large loads; (5) requiring, in specific circumstances, some new large loads to be subject to curtailment prior to the deployment of pre-emergency demand response pursuant to a “connect and manage” framework; (6) immediate initiation of reliability backstop procurement; (7) holistic review of investment incentives in PJM’s energy, reserve, and capacity markets; and (8) feedback on whether to extend the price collar for the 2028/2029 and 2029/2030 capacity auctions.¹⁰⁰

32. Additionally, on January 16, 2026, governors from each of the 13 states in PJM met with the White House National Energy Dominance Council and issued a statement of principles calling on PJM to: (1) provide 15-year price certainty for new capacity resources by holding a reliability backstop auction to procure new capacity resources commencing no later than September 2026; (2) allocate the costs of capacity procured through the reliability backstop auction to load serving entities with new data centers that have not self-procured new capacity or agreed to be curtailable; (3) extend the existing price collar to the next two Base Residual Auctions; (4) refine load forecasting methodologies by improving large load modeling assumptions; (5) accelerate ongoing generator interconnection studies; and (6) embark on a stakeholder process to reform the capacity market to ensure long-term viability.¹⁰¹

33. In response, PJM has initiated stakeholder processes on several items. The PJM Board initiated a new CIFP stakeholder process to engage stakeholders in the

¹⁰⁰ PJM, *Board Decisional Letter on Critical Issue Fast Path - Large Load Additions* (Jan. 16, 2026), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf>. PJM has since submitted its proposal to extend the price collar for the 2028/2029 and 2029/2030 delivery years, which the Commission accepted on April 28, 2026. *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,076 (2026). PJM has also since submitted its proposal for a temporary, expedited generator interconnection process (Expedited Interconnection Track), which the Commission accepted on June 9, 2026. PJM EIT Order, 195 FERC ¶ 61,197.

¹⁰¹ U.S. Department of Energy, *Statement of Principles Regarding PJM* (Jan. 16, 2026), <https://www.energy.gov/documents/statement-principles-regarding-pjm>.

development of a reliability backstop procurement mechanism.¹⁰² PJM also developed a Connect and Manage Senior Task Force to consider the “connect and manage” framework to manage the reliability challenges during the transition period in which new load additions are outpacing the additions of new capacity in the PJM system.¹⁰³ Following initial stakeholder workshops, the PJM Board decided to expand the scope of the CIFP regarding the reliability backstop procurement mechanism to include the “connect and manage” framework, given the substantive overlap between the two proposals.¹⁰⁴ PJM expects to develop a comprehensive proposal by the end of June, which it expects to file with the Commission shortly thereafter, with the goal of procuring any shortfall resulting from the upcoming Base Residual Auction through a centralized procurement in September 2026.¹⁰⁵ PJM has additionally issued a report examining market design and investment incentives in light of rising demand, which is driven in part by the expansion of large loads, and constrained supply.¹⁰⁶ PJM has scheduled a series of workshops through August 2026 to develop recommendations based on the choices presented in the report.¹⁰⁷

34. While we are encouraged by PJM’s stakeholder efforts, and by its initial attention to the pressing concerns associated with large and co-located loads,¹⁰⁸ and to the

¹⁰² PJM, *Critical Issue Fast Path – Reliability Backstop Procurement*, <https://www.pjm.com/committees-and-groups/cifp-rbp>.

¹⁰³ PJM, *Connect and Manage Senior Task Force*, <https://www.pjm.com/committees-and-groups/task-forces/camstf>.

¹⁰⁴ PJM, Third Supplemental Informational Report, Docket No. EL25-49-000, et al. (filed May 20, 2026); *see also* PJM, *Critical Issue Fast Path - Reliability Backstop Procurement / Connect & Manage*, <https://www.pjm.com/committees-and-groups/cifp-rbp>.

¹⁰⁵ PJM, Third Supplemental Informational Report, Docket No. EL25-49-000, et al. (filed May 20, 2026).

¹⁰⁶ PJM, *Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment to Support Durable Reliability* (May 6, 2026), <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2026/20260506-powering-reliability-through-market-design.pdf>.

¹⁰⁷ PJM, *Powering Reliability Through Market Design Workshops*, <https://www.pjm.com/committees-and-groups/workshops/prtmdw>.

¹⁰⁸ PJM November 21 ANOPR Comments at 12; *see also* PJM, *Large Load Additions Workshop*, at 1 (May 9, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02-->

Secretary's interest in these issues,¹⁰⁹ we are initiating this FPA section 206 proceeding in order to ensure that PJM's ongoing processes generate reforms that are sufficiently timely and comprehensive to address the concerns we today identify. As such, and as the Commission explained in the April Order Regarding Intent to Act, we find that the Commission must now take further action to ensure that PJM promptly proposes revisions to ensure that its Tariff remains just and reasonable.

III. Discussion

35. Based on the discussion below, pursuant section 206 of the FPA, we direct PJM and the Transmission Owners, within 60 days of the date of this order, to either:

(1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential without provisions addressing:

(a) the application process, study procedures, and ongoing operational requirements that apply to Eligible Customers seeking transmission service on behalf of large loads;

(b) additional transparency concerning the Network Upgrade costs to provide transmission service to Eligible Customers on behalf of large loads, a *pro forma* cost recovery agreement between PJM, the relevant transmission owner and Eligible Customer taking transmission service on behalf of the large load to mitigate the risk of cost shifting among transmission customers, and a mechanism to ensure such payments are appropriately credited towards transmission owners' transmission revenue requirements consistent with the Commission's cost-of-service regulations;

(c) transmission services that reflect Eligible Customers taking transmission service on behalf of flexible large loads that are willing and able to limit their use of the transmission system under certain conditions; and

(d) the rates, terms, and conditions of service applicable to interconnection customers serving electrically proximate large load or co-located load; or

-large-load-additions-workshop---presentation.pdf (discussing challenges with reliability of connecting large loads); PJM IMM, *Planning for Large Load Additions* (Jan. 7, 2025), https://www.monitoringanalytics.com/reports/Presentations/2025/IMM_PC_Large_Load_Additions_20250107.pdf.

¹⁰⁹ See *supra* PP 6-7.

(2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential and, therefore, proceeds to establish a replacement Tariff.

36. We also direct PJM to submit, within 30 days of the date of issuance of this order, an informational report on how PJM intends to ensure that adequate generation will be available to serve existing and new large loads.

37. Interested entities may respond within 30 days of PJM's and the Transmission Owners' filings, addressing either or both of: (1) whether the existing Tariff remains just and reasonable and not unduly discriminatory or preferential; and (2) if not, what changes to the Tariff should be implemented as replacement rates.

38. We recognize that PJM and/or the Transmission Owners (to the extent the matters addressed herein implicate aspects of the Tariff over which they have the filing rights) may elect to address some or all of the issues discussed in this order by proposing revisions to the Tariff pursuant to their applicable FPA section 205 filing rights. We strongly encourage this. Although both the Secretary's ANOPR and our own Order Regarding Intent to Act expressly recognized (and indeed encouraged) that possibility,¹¹⁰ no such filings were received from PJM by the Commission prior to the issuance of this order. Should PJM and/or the Transmission Owners elect to make such filings in response to this order, those filings should state explicitly that the proposals are being submitted under FPA section 205. Should PJM and/or the Transmission Owners submit a filing under FPA section 205, they should also explain which of the Commission's above directives their filing addresses and how it resolves them. Additionally, any such filing should provide a reasoned explanation for how the proposal will avoid disrupting existing commercial arrangements and clearly identify a reasonable effective date that accommodates such existing commercial arrangements.

39. The Commission will consider requests from PJM and/or the Transmission Owners to hold, for up to 90 days, all or certain aspects of this FPA section 206 proceeding in abeyance, including the deadline to respond to this order. Any such abeyance, which will begin as of the deadline to respond to this order, would be considered to provide PJM and the Transmission Owners time while they work through the stakeholder processes to develop FPA section 205 filings to revise the Tariff to address the issues raised in this order. Requests for a full or partial abeyance¹¹¹ should be

¹¹⁰ See ANOPR at P 32; Order Regarding Intent to Act, 195 FERC ¶ 61,045 at P 5.

¹¹¹ A partial abeyance may be appropriate to the extent PJM is developing FPA section 205 filings in response to only a subset of the directives in this order. For any

submitted prior to the deadline to respond to this order, specifically within 45 days of issuance of this order, to allow time for the Commission to act on the abeyance request. We emphasize that we will not grant such abeyances reflexively, that any abeyance will be limited to 90 days, and that we will look with great disfavor toward requests to extend the abeyance period. We anticipate that successful abeyance requests, if any, will include both (1) a robust description of the content of a potential future filing under FPA section 205 and (2) a reasoned and specific explanation of when such a filing is expected to be made.

40. In cases where, as here, the Commission institutes a section 206 investigation on its own motion, section 206(b) of the FPA requires that the Commission establish a refund effective date that is no earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than five months after the publication date. In such cases, in order to give maximum protection to customers, and consistent with our precedent, we have historically tended to establish the section 206 refund effective date at the earliest date allowed by section 206, and we do so here as well.¹¹² That date is the date of publication of notice of initiation of this proceeding in the *Federal Register*.

A. Transmission Service to Eligible Customers on Behalf of Large Loads

41. We today make a preliminary finding that PJM's Tariff appears to be unjust and unreasonable because it lacks provisions that address, with sufficient clarity and consistency, how PJM and/or the Transmission Owners will timely study (i.e., within 60-90 days of receiving the request) the provision of transmission service to Eligible Customers on behalf of large loads.¹¹³

42. Throughout this order, we use the phrase "the provision of transmission service to Eligible Customers on behalf of large loads" to encompass the provision of new, modified, or additional jurisdictional transmission service to Eligible Customers on behalf of large loads. We note that this phrase is not limited to instances where an Eligible Customer submits an application to request new transmission service. It also includes instances where an Eligible Customer requests a new or modified point of

remaining directives, we expect a response to this order within the 60-day deadline set forth herein.

¹¹² See, e.g., *Idaho Power Co.*, 145 FERC ¶ 61,122 (2013); *Canal Elec. Co.*, 46 FERC ¶ 61,153, *order on reh'g*, 47 FERC ¶ 61,275 (1989).

¹¹³ As discussed below, our findings here also apply to the study process for unbundled retail transmission service requests by end-use large load customers, as allowed by state law or voluntary utility rules.

delivery to serve a large load, where a large load seeks a new or modified delivery point as an unbundled retail transmission service customer, or where large loads are otherwise included in an Eligible Customer's reported load growth and that Eligible Customer is taking NITS.

43. We direct PJM and the Transmission Owners to the extent the matters addressed herein implicate aspects of the Tariff over which they have the filing rights, to explain whether the Tariff remains just and reasonable without an application process, study procedures, and ongoing operational requirements that address the unique characteristics and challenges of providing transmission service to Eligible Customers on behalf of large loads, or to propose appropriate Tariff revisions.

1. Jurisdiction

44. At the outset, we clarify the principles relating to the Commission's jurisdiction over the matters relevant to the integration of large loads onto the transmission system and the impacts of large loads on the transmission system. We recognize that rates, terms, and conditions associated with the addition of and service to large loads implicate both federal and state interests. We also recognize that resolution of issues related to large load additions will require the involvement of both federal and state actors, including the Commission, state public utility commissions, and other state and local entities. We are encouraged by efforts made at the state level to address issues related to large load additions that fall within state jurisdiction.¹¹⁴

45. As discussed below, however, certain aspects of the process for integrating large loads onto the transmission system fall squarely within the Commission's exclusive jurisdiction. Specifically, we find that it is within the Commission's exclusive authority to ensure that transmission provider and/or transmission owner tariffs include sufficiently clear and consistent provisions governing how transmission service to Eligible Customers on behalf of large loads interconnecting to the transmission system will be studied, including whether new or upgraded transmission facilities are necessary to provide the requested transmission service. The Commission has jurisdiction over the study process for transmission service to both Eligible Customers on behalf of large loads and unbundled retail transmission service to end-use large load customers where, pursuant to state law or a public utility's voluntary offer of such service, the large load is an Eligible Customer under the transmission provider and/or transmission owner tariffs.¹¹⁵

¹¹⁴ See generally NARUC April 14 ANOPR Comments (highlighting action taken by state public utility commissions related to large loads).

¹¹⁵ Under the *pro forma* OATT, Eligible Customers include end-use customers seeking unbundled retail transmission service, pursuant to state law or public utility's

46. The Commission is a creature of statute and has jurisdiction over only those matters that Congress has given it the authority to regulate.¹¹⁶ That authority includes jurisdiction over the wholesale sale and transmission of electricity in interstate commerce, including all facilities used for such sale and transmission.¹¹⁷ As relevant here, the Commission must ensure that the rates, charges, and classifications for such transmission of electricity—as well as the practices directly affecting such transmission of electricity—are just and reasonable and not unduly discriminatory or preferential.¹¹⁸ The Supreme Court has held that the Commission’s authority over interstate transmission is not limited to wholesale transmission service and that the Commission has authority over unbundled retail transmission service.¹¹⁹ As part of its transmission authority, the Commission has exercised jurisdiction over the terms of certain interconnections to the transmission system as an element of transmission service,¹²⁰ including the interconnection of wholesale load to the transmission system.¹²¹

47. As applied to large load additions to the transmission system, these principles mean that the Commission has exclusive jurisdiction over the rates, terms, and conditions of interstate transmission service to Eligible Customers on behalf of large loads connecting to the transmission system, and the practices directly affecting the provision of such interstate transmission of electricity. An essential component of providing such transmission service is the process by which the transmission provider and/or

voluntary offer of such service. *Pro forma* OATT, § 1.12 (Definitions – Eligible Customer); *see also* PJM Tariff pt. VIII, § 400 (Definitions E) (2.0.0).

¹¹⁶ *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002).

¹¹⁷ 16 U.S.C. § 824(b)(1).

¹¹⁸ *Id.* §§ 824d, 824e; *see FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260, 278 (2016) (*EPSA*) (approving “a common-sense construction of the FPA’s language, limiting FERC’s ‘affecting’ jurisdiction to rules or practices that ‘directly affect the wholesale rate’” (cleaned up)).

¹¹⁹ *New York v. FERC*, 535 U.S. 1, 17, 19-20 (2002) (upholding the Commission’s exercise of jurisdiction over unbundled retail transmission service).

¹²⁰ *Tenn. Power Co.*, 90 FERC ¶ 61,238, at 61,761 (2000) (*Tennessee Power*), *order denying reh’g*, 91 FERC ¶ 61,271 (2000); *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103, at P 9 (2003); *see also Laguna Irrigation Dist.*, 91 FERC ¶ 61,340, at 62,152 (2000).

¹²¹ *Pac. Gas & Elec. Co.*, 109 FERC ¶ 61,392, at P 37 (2004); *Pac. Gas & Elec. Co.*, 115 FERC ¶ 61,193, at PP 36-38 (2006).

transmission owner evaluates (1) whether it can provide the requested transmission service and (2) the impact that providing such transmission service will have on the jurisdictional transmission system, including determining whether any new or upgraded transmission facilities are needed to provide transmission service while maintaining reliable operation of the transmission system. This transmission service study process determines what Network Upgrades are needed to provide transmission service to Eligible Customers on behalf of large loads, the costs of which are included in transmission rates. As such, this study process directly affects Commission-jurisdictional transmission rates.¹²² The Commission has exclusive authority to ensure that the process to study the provision of transmission service to Eligible Customers is just and reasonable and not unduly discriminatory or preferential. We therefore find that we have authority to ensure that tariffs include provisions that clearly and consistently address the study process for the provision of transmission service to Eligible Customers on behalf of large loads, including the unique impacts that providing transmission service to Eligible Customers on behalf of large loads may have on the transmission system.

48. At the same time, we continue to recognize that the FPA expressly reserves to states the authority over any other sale of electric energy, including retail sales and wholesale sales not in interstate commerce (such as wholesale sales within the Electric Reliability Council of Texas region), as well as facilities used for the generation and distribution of electricity.¹²³ As such, we recognize that states will continue to regulate: (1) the specific terms of retail sales to large load;¹²⁴ (2) which entities may make retail sales within their borders, including which entities are legally permitted to provide electricity to retail large load customers;¹²⁵ and (3) any siting decisions and construction

¹²² Cf. *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at P 112 (2011) (“It is through the transmission planning process that public utility transmission providers determine which transmission facilities will more efficiently or cost-effectively meet the needs of the region, the development of which directly impacts the rates, terms and conditions of jurisdictional service.”).

¹²³ 16 U.S.C. § 824(b)(1); see *Dayton Power & Light Co. v. FERC*, 126 F.4th 1107, 1129 (6th Cir. 2025).

¹²⁴ See *EPSA*, 577 U.S. at 279-80 (recognizing state authority over retail electricity sales); *New York v. FERC*, 535 U.S. at 28 (same).

¹²⁵ PJM Show Cause Order, 190 FERC ¶ 61,115 at PP 68-69.

associated with the large load project.¹²⁶ Nothing in this order is intended to intrude upon state authority over retail service to large loads.

49. In sum, we today exercise our authority to ensure that the process by which jurisdictional transmission providers and/or transmission owners will study the provision of jurisdictional transmission service to Eligible Customers on behalf of large loads interconnecting to the transmission system, including where, as allowed by state law or a public utility's voluntary offer of such service, an end-use large load seeks unbundled retail transmission service, is just and reasonable and not unduly discriminatory or preferential. Pursuant to that authority, we find that PJM's Tariff appears to be unjust and unreasonable or unduly discriminatory or preferential because it lacks sufficiently clear and consistent provisions regarding the study process related to the provision of transmission service to Eligible Customers on behalf of large loads. We need not comprehensively address the Commission's jurisdiction over other aspects of the addition of large loads to the transmission system at this time.

2. Tariff Provisions

50. In the following section, we begin by considering PJM's Tariff as it relates to how PJM and/or the Transmission Owners will study the provision of transmission service to Eligible Customers on behalf of large loads and explain our concerns that the lack of sufficiently clear and consistent provisions regarding the study process for the provision of transmission service to Eligible Customers on behalf of large loads is unjust and unreasonable or unduly discriminatory or preferential. We then consider whether the Tariff is unjust and unreasonable without certain elements. First, we consider whether the Tariff lacks sufficiently clear and consistent Tariff provisions establishing an appropriate definition of large load, as a separate category of load. Second, we consider whether the Tariff lacks sufficiently clear and consistent Tariff provisions establishing an application process and requirements for Eligible Customers requesting transmission service on behalf of large loads and a study process that considers the unique operational challenges of providing transmission service to Eligible Customers on behalf of large loads. Third, we consider whether the Tariff lacks sufficiently clear and consistent Tariff provisions establishing ongoing operational requirements necessary to ensure that PJM can reliably provide transmission service given the unique operational impacts on the transmission system of providing transmission service to Eligible Customers on behalf of large loads. Finally, we consider whether the Tariff requires such ongoing operational

¹²⁶ See, e.g., *Citizens Action Coal. of Ind., Inc. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025) (citing 16 U.S.C. § 824(b)(1)) (recognizing state authority over generation resource mix, including through their siting authority); Order No. 1000, 136 FERC ¶ 61,051 at P 107 (acknowledging state authority over siting, permitting, and construction of transmission facilities).

requirements for Eligible Customers taking transmission service on behalf of large loads to be memorialized in service agreements.

51. We preliminarily find that PJM's Tariff appears to be unjust and unreasonable or unduly discriminatory or preferential because it does not contain provisions addressing with sufficient clarity and consistency how PJM and/or the Transmission Owners will study the provision of transmission service to Eligible Customers on behalf of large loads. We recognize that PJM and/or the Transmission Owners may have existing load integration processes, including studies that are performed in evaluating the provision of transmission service to Eligible Customers on behalf of large loads.¹²⁷ However, we are concerned that those processes and any required studies with regard to the provision of transmission service are not described in the Tariff with the degree of clarity and specificity necessary to ensure that the transmission provider can mitigate operational risks of providing transmission service to Eligible Customers on behalf of large loads, given their impact on the transmission system, avoid disputes regarding how studies are conducted, deter speculative or duplicative requests for transmission service by Eligible Customers on behalf of large loads, and help avoid excessive and unnecessary Network Upgrades. Moreover, we are concerned that the existing Tariff does not contain other elements akin to those described below, which we preliminarily find may be necessary to ensure that the rates, terms, and conditions of jurisdictional transmission service are just and reasonable.

52. At the outset, we recognize that the Transmission Owners may be primarily responsible for conducting the studies that (1) evaluate whether a large load may be interconnected to the transmission system and served by the Eligible Customer, and (2) determine whether Network Upgrades are necessary to provide transmission service. We appreciate that this role may stem from how PJM and the Transmission Owners allocated rights and responsibilities in the governing documents establishing PJM. We do not seek to alter that allocation of rights and responsibilities.

53. We are nonetheless concerned that PJM's Tariff lacks a study process that addresses the unique operational and reliability challenges that providing transmission service to Eligible Customers on behalf of large loads presents to the transmission system. Large loads can be more energy intensive and geographically concentrated than traditional load, and exhibit different load profiles and operational characteristics.¹²⁸ PJM

¹²⁷ See *supra* PP 20-24.

¹²⁸ See, e.g., SPP HILL Order, 194 FERC ¶ 61,031 at PP 7-8; NERC, *Characteristics and Risks of Emerging Large Loads* (July 2025), <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper->

itself has recognized that enhanced large load saturation can have a disproportionate impact on system reliability, including voltage and frequency fluctuations due to their size and unique characteristics, if mitigating operational steps and other protection schemas are not developed and implemented.¹²⁹ The PJM Board has also recognized that the scale, pace, and characteristics of large load growth present significant operational and planning challenges.¹³⁰ As a result, providing transmission service to Eligible Customers on behalf of large loads may be more complex and could raise greater reliability concerns for the transmission system, relative to a situation where Eligible Customers seek transmission service on behalf of traditional load.

54. Without a clear and consistent process to study the provision of transmission service to Eligible Customers on behalf of large loads, PJM and/or the Transmission Owners may not fully capture the transmission system impacts of providing such transmission service, which could result in significant operational risks for the transmission system. Furthermore, we are concerned that, without sufficiently clear and consistent Tariff provisions, PJM will not have the ongoing visibility and operational control necessary to provide reliable transmission service.

55. We are also concerned that the absence of sufficiently clear and consistent Tariff provisions for how PJM and/or the Transmission Owners will study the provision of transmission service to Eligible Customers on behalf of large loads will lead to disputes over a variety of issues—e.g., study timelines and delays,¹³¹ how the transmission service needed on behalf of the large load is studied,¹³² what types of Network Upgrades are

characteristics-and-risks-of-emerging-large-loads.pdf (NERC Characteristics and Risks of Large Loads).

¹²⁹ PJM November 21 ANOPR Comments at 12.

¹³⁰ See PJM Board Letter. PJM TOs further note that many data centers' initial loads are significantly lower when they first enter commercial operation, but following expansion and full potential of operation capacity, their demand increases to much higher levels. PJM TOs November 21 ANOPR Comments at 9.

¹³¹ See, e.g., Institute for Progress November 21 ANOPR Comments at 7-8; Microsoft November 21 ANOPR Comments at 9; ODEC December 5 ANOPR Comments at 4; Vistra November 21 ANOPR Comments at 21 (discussing lack of defined load interconnection process in PJM and lack of detail in PJM Tariff and manuals regarding load integration study).

¹³² Commenters raised concern that large loads are not studied with consideration of their known operating characteristics, including their willingness to be flexible or curtailable. See, e.g., ClearPath November 21 ANOPR Comments at 5-6; Constellation November 21 ANOPR Comments at 23-24; Critical Loop November 21 ANOPR

considered, and how required Network Upgrades to provide the requested transmission service are determined.¹³³ Such disputes may arise from the lack of transparency in how studies are performed and how decisions will be made.¹³⁴ We are thus concerned that the lack of clear and consistent provisions in PJM's Tariff related to the study process for the provision of transmission service to Eligible Customers on behalf of large loads appears to be unjust and unreasonable or unduly discriminatory or preferential.

56. Lastly, we are concerned that PJM's existing Tariff fails to deter speculative or duplicative requests for transmission service by Eligible Customers on behalf of large loads. Many ANOPR comments assert that clear and consistent provisions establishing study timelines and costs, readiness requirements, and/or penalties will deter speculative or duplicative requests related to large load additions.¹³⁵ Commenters explain that

Comments at 3; GridCare December 5 ANOPR Comments at 1-2; L. Lynne Kiesling November 21 ANOPR Comments at 10.

¹³³ Specifically, commenters raised concern that transmission providers/owners may only consider traditional transmission infrastructure or that there is a lack of consideration of alternative transmission solutions. *See, e.g.*, ACORE November 21 ANOPR Comments at 3-4, 6-7; American Terawatt November 21 ANOPR Comments at 4-5; Calibrant November 21 ANOPR Comments at 1-2, 3; CEBA November 21 ANOPR Comments at 9-10; Chamber of Commerce November 21 ANOPR Comments at 3; CTC Global Corporation November 21 ANOPR Comments at 1-3; DCC November 21 ANOPR Comments at 10-11; GridCARE December 5 ANOPR Comments at 4; Industrial Customers November 21 ANOPR Comments at 27-28; Infrastructure Masons December 5 ANOPR Comments at 18; Iron Mountain Data Centers, LLC November 21 ANOPR Comments at 3-4; Land Trust Alliance November 21 ANOPR Comments at 5-6; PIOs November 21 ANOPR Comments at 22; Southeast PIOs November 21 ANOPR Comments at 44-45; WATT and Advancing Modern Powerlines November 21 ANOPR Comments at 5-8.

¹³⁴ *See, e.g.*, CEBA November 21 ANOPR Comments at 12; ECA December 5 ANOPR Comments at 1-2; Eolian November 21 ANOPR Comments at 17-18; EPSA November 21 ANOPR Comments at 6; Infrastructure Masons December 5 ANOPR Comments at 4, 6-7; Southeast PIOs November 21 ANOPR Comments at 39-40; Switch December 5 ANOPR Comments at 3; Tract November 21 ANOPR Comments at 5; Vantage November 21 ANOPR Comments at 5-6; Verrus November 21 ANOPR Comments at 6, 12; Vistra December 5 ANOPR Comments at 27.

¹³⁵ *See, e.g.*, ACORE November 21 ANOPR Comments at 6; AEU November 21 ANOPR Comments at 17-18; Amazon November 21 ANOPR Comments at 6; Crusoe December 5 ANOPR Comments at 5-6; EDF Power November 21 ANOPR Comments at 12-13; EEI November 21 ANOPR Comments at 20; Fervo November 21 ANOPR

speculative requests may bog down and delay the study process, wasting time and resources for transmission providers;¹³⁶ result in inaccurate study results or delays for other Eligible Customers seeking transmission service on behalf of load;¹³⁷ create a substantial risk of cost shifts if the large load additions do not materialize as planned;¹³⁸ and distort load forecasts.¹³⁹ Clear and consistent study procedures that include readiness requirements (i.e., meaningful milestones and/or financial commitments) can help ensure that Eligible Customers' requests for transmission service on behalf of large loads are more viable and more likely to materialize as planned, given that they must meet specific milestones and/or pay costs to proceed.

57. More specifically, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks sufficiently clear and consistent Tariff provisions that

Comments at 3; GridCare December 5 ANOPR Comments at 5; Invenergy November 21 ANOPR Comments at 6; Microsoft November 21 ANOPR Comments at 9; Ohio FEA November 21 ANOPR Comments at 4.

¹³⁶ See, e.g., Eolian November 21 ANOPR Comments at 17-18; GridCare December 5 ANOPR Comments at 5; Illinois AG November 21 ANOPR Comments at 9-10; Institute for Progress November 21 ANOPR Comments at 9; OCC November 21 ANOPR Comments at 7-8; Ohio FEA November 21 ANOPR Comments at 4; Vistra November 21 ANOPR Comments at 23.

¹³⁷ See, e.g., Amazon November 21 ANOPR Comments at 6; CEBA November 21 ANOPR Comments at 8; ClearPath November 21 ANOPR Comments at 4; Geronimo November 21 ANOPR Comments at 12; TAPS November 21 ANOPR Comments at 14-15.

¹³⁸ See, e.g., AES November 21 ANOPR Comments at 10-11; Buckeye November 21 ANOPR Comments at 1-2; Exelon November 21 ANOPR Comments at 3; NRECA November 21 ANOPR Comments at 9; OCC November 21 ANOPR Comments at 9; Southeast PIOs November 21 ANOPR Comments at 20; State Entities November 21 ANOPR Comments at 7-8; TAPS November 21 ANOPR Comments at 15, 22-24; Tri-State November 21 ANOPR Comments at 6, 8; Vistra November 21 ANOPR Comments at 23.

¹³⁹ See, e.g., CEBA November 21 ANOPR Comments at 8; EEI November 21 ANOPR Comments at 20; ELCON November 21 ANOPR Comments at 7; Invenergy November 21 ANOPR Comments at 6; GridCare December 5 ANOPR Comments at 5; OCC November 21 ANOPR Comments at 9; PIOs November 21 ANOPR Comments at 5; Southeast PIOs November 21 ANOPR Comments at 41; Talen November 21 ANOPR Comments at 9.

address certain aspects of the process to provide transmission service to Eligible Customers on behalf of large loads, including:

- (1) a definition of large load sufficient to capture loads that present the unique challenges described herein;
- (2) the application process for requesting transmission service to Eligible Customers on behalf of large loads and the study procedures, including readiness requirements, for studying the provision of transmission service to Eligible Customers on behalf of large loads;
- (3) ongoing operational requirements for transmission customers¹⁴⁰ serving large loads necessary to ensure reliable operation of the transmission system; and
- (4) *pro forma* provisions in transmission service agreements to memorialize these terms.

58. First, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks a definition of large load, as a new category of load. As PJM acknowledges, integrating large loads poses specific challenges to transmission system operation given their size, operational behavior, and unique potential to impact the transmission system.¹⁴¹ An appropriate definition, including a load size and interconnection voltage threshold, should be based on the characteristics of PJM's transmission system. That said, based on the record in the ANOPR proceeding,¹⁴² it appears that it would be reasonable to define a large load as a new, commercial or

¹⁴⁰ We note that such ongoing operational requirements should apply to transmission customers, rather than Eligible Customers, as these requirements apply after the Eligible Customer has an executed (or a filed unexecuted) service agreement for transmission service and have become transmission customers under the Tariff.

¹⁴¹ PJM November 21 ANOPR Comments at 12.

¹⁴² See, e.g., Constellation November 21 ANOPR Comments at 13 (supporting a voltage threshold); DTE November 21 ANOPR Comments at 3, 17-19 (recommending a threshold of an amount between 50 MW to 100 MW); Eolian November 21 ANOPR Comments at 8-9 (recommending a voltage threshold greater than or equal to an amount between 60 kV to 100 kV); Illinois AG November 21 ANOPR Comments at 7 (supporting a 20 MW or 50 MW threshold and consideration of other factors, such as voltage level); ITC November 21 ANOPR Comments at 3 (recommending a threshold of between 50 MW to 100 MW); Nebraska Board November 21 ANOPR Comments at 4 (proposing a 50 MW threshold); New Mexico Commission November 21 ANOPR Comments at 5 (proposing a 50 MW threshold).

industrial customer, located at a single site behind one or more points of interconnection, and that has a peak load of 50 MW or greater, interconnects to the transmission system at a voltage level of greater than 69 kV, and is not part of a co-location arrangement. In its response to this order, PJM should explain whether the Tariff remains just and reasonable without such a definition, or propose Tariff revisions establishing its own definition of large load.

59. Second, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks sufficiently clear and consistent Tariff provisions establishing the application process and study procedures that will be used when PJM and/or the Transmission Owners evaluate the provision of transmission service to Eligible Customers on behalf of large loads. PJM should explain whether the Tariff remains just and reasonable, for example, without: (1) an application process that accepts Eligible Customers' applications for transmission service on behalf of large loads on a rolling basis; (2) a non-refundable application fee and sufficient readiness requirements that escalate at distinct phases of the study process to deter duplicative or speculative requests for transmission service (e.g., meaningful milestones and/or financial commitments); and (3) information and data requirements that Eligible Customers must submit to PJM and/or the Transmission Owners regarding the characteristics of the large load on behalf of which the Eligible Customer is taking transmission service, including disclosure to PJM of any substantially similar pending transmission service requests on behalf of the same large load customer.¹⁴³ PJM may also elect to propose Tariff revisions establishing such an application process, fee, and requirements.

60. Further, PJM's Tariff appears to lack sufficiently clear and consistent provisions establishing a study process for evaluating the provision of transmission service to Eligible Customers on behalf of large loads that considers the unique characteristics and impacts of large loads on the transmission system. For example, we are concerned that PJM's Tariff may not clearly and consistently require PJM or the Transmission Owners to conduct studies that evaluate the transmission system's ability to withstand risks observed from analyzed large load behavior created by the large load at the point of interconnection, or any other necessary supplemental studies to evaluate the impact of providing transmission service to Eligible Customers on behalf of large loads.¹⁴⁴

¹⁴³ The Electric Reliability Council of Texas (ERCOT) has proposed a similar disclosure requirement in its Batch Zero process for large load interconnections. ERCOT Planning Guide, § 9.7.1(1)(b) (proposed Mar. 4, 2026).

¹⁴⁴ See generally NERC, *Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations* (Sep. 2025), <https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large->

Additionally, we preliminarily find that PJM's Tariff appears unjust and unreasonable because it lacks appropriate provisions recognizing within the transmission service request study process the unique operational characteristics of large loads that are willing and able to limit their energy withdrawals under certain conditions, which may thereby lessen or potentially avoid the need for certain Network Upgrades. While flexible large loads can reduce the demand on the transmission system, and therefore potentially reduce the need for additional transmission capacity, additional informational and study requirements may be necessary to account for the dynamic nature of these types of loads while maintaining reliability.¹⁴⁵ Additionally, we note that accurate models using Electromagnetic Transient studies may help to ensure that transmission service needed on behalf of large loads can be provided without compromising reliability.¹⁴⁶

61. Additionally, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks clear and consistent provisions requiring the evaluation of alternative transmission technologies¹⁴⁷ as potential solutions to accommodate an Eligible Customer's request for transmission service on behalf of a large load. Alternative transmission technologies can add more capacity on existing transmission lines quickly,

loads.pdf (finding that unique operational characteristics of large loads necessitate enhancements to studies).

¹⁴⁵ See, e.g., AEMA November 21 ANOPR Comments at 6; Thermal Battery Alliance November 21 ANOPR Comments at 7; Verrus November 21 ANOPR Comments at 10.

¹⁴⁶ See, e.g., NERC, *Draft Reliability Guideline: Risk Mitigation for Emerging Large Loads* 6-7 (May 2026), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/reliabilityguideline_riskmitigationforemerginglargeloads.pdf; NERC, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads* 31 (Mar. 2026), <https://www.nerc.com/globalassets/our-work/guidelines/reliability/white-paper---assessment-of-gaps.pdf>; see also SPP HILL Order, 194 FERC ¶ 61,031 at P 62.

¹⁴⁷ For purposes of this order, alternative transmission technologies include static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors, tower lifting, and dynamic line ratings. We note that the Commission has also referred to these types of technologies as Grid Enhancing Technologies (GETs).

often within one to three years.¹⁴⁸ Unlike with traditional load growth,¹⁴⁹ large load customers often have development timelines requiring interconnection to the transmission system faster than traditional Network Upgrades can be built, necessitating a sufficient evaluation of alternative transmission technologies that can more quickly accommodate transmission service requests from Eligible Customers on behalf of large loads.¹⁵⁰ The Commission has previously recognized that alternative transmission technologies have the potential to mitigate or defer the need for traditional Network Upgrades and often can be deployed both more quickly and at lower cost than traditional Network Upgrades, and therefore failing to consider whether alternative transmission technologies can meet transmission needs more efficiently or cost-effectively than traditional Network Upgrades has the potential to render Commission-jurisdictional rates

¹⁴⁸ WATT and Advancing Modern Powerlines November 21 ANOPR Comments at 5-6.

¹⁴⁹ See, e.g., SPP HILL Order, 194 FERC ¶ 61,031 at P 7 (explaining that the HILL proposal was needed in part due to large load customers frequently requesting transmission service within months rather than years of their intended commercial operation, straining legacy regulatory frameworks and planning processes originally designed for slow, incremental, and predictable load growth); see also Commission Staff, *2025 State of the Market Report* 8 (Mar. 2026) (“[D]ata centers have characteristics unlike more traditional loads [including] size, strong desire for faster interconnection, and potential flexibility.”).

¹⁵⁰ Exec. Off. of the President, *Winning the Race: America’s AI Action Plan* 1-2, 15 (July 2025), <https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf> (explaining that accelerated deployment of AI data centers is a critical matter of national security and international economic competitiveness, and recommending federal policy action to optimize the existing grid through advanced grid technologies); WATT and Advancing Modern Powerlines November 21 ANOPR Comments at 5-8 (“[Alternative transmission technologies’] deployment timelines are more aligned with the interconnection needs of new large loads, which may only take 1-2 years to construct.”); Industrial Customers November 21 ANOPR Comments at 28 (“Achieving speed-to-power in the near-term, while also protecting customers, will require the use of GETs, advanced reconductoring, and unlocking all available system capacity.”); Energy Systems Integration Group, *Historical and Modern Large Loads: Characteristics, Context, and Industry Action to Meet Grid and Customer Needs* 4 (Mar. 2026), <https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Historical-vs-Modern-Large-Loads-white-paper-2026.pdf> (describing the timing mismatch between how long it takes to build a new data center and how long it takes to plan, permit, and build transmission).

unjust and unreasonable.¹⁵¹ Further, to the extent Network Upgrade costs to accommodate an Eligible Customer's request for transmission service on behalf of a large load are rolled into a transmission owner's transmission revenue requirement, transmission customers other than the Eligible Customer may bear a portion of those Network Upgrade costs, highlighting the need for clear and consistent provisions requiring the evaluation of least-cost options like alternative transmission technologies to mitigate the rate impact on all transmission customers.

62. PJM should explain whether the Tariff remains just and reasonable without provisions that: (1) require the evaluation of alternative transmission technologies in transmission service request studies, using models that are capable of evaluating the transmission system to accurately account for advanced transmission technologies, in all instances, without the need for a request from the Eligible Customer seeking transmission service on behalf of a large load; and (2) if traditional Network Upgrades are selected instead of alternative transmission technologies, inclusion in the study report to the Eligible Customer seeking transmission service on behalf of a large load of a sufficiently clear demonstration of why alternative transmission technologies are not feasible (i.e., would not resolve reliability violations identified or meet the relevant planning criteria) or would not result in lower costs or a faster timeline for accommodating the transmission service request; or propose Tariff revisions establishing such provisions. This transparency and informational requirement is warranted for the regulatory scheme we are establishing for transmission service requests by Eligible Customers on behalf of large loads given demand from and the expedited development timelines for large load customers. We underscore that we are not mandating the use of alternative transmission technologies. To the extent stakeholders believe that specific characteristics of providing transmission service to Eligible Customers on behalf of large loads warrant requirements beyond those contemplated here, we seek further briefing.

63. Finally, based on the record, it appears reasonable that such study processes, culminating in a report to the Eligible Customer with the results of the studies, including any Direct Assignment Facilities and Network Upgrades necessary to accommodate the transmission service request as well as a non-binding good-faith estimate of the cost and the time to construct such facilities, should take no more than 60-90 days calendar days to

¹⁵¹ *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054 at P 1583, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024); *see also Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 at P 1201, *order on reh'g*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024), *order on reh'g*, Order No. 1920-B, 191 FERC ¶ 61,026 (2025).

complete.¹⁵² To the extent PJM or the Transmission Owners already have such procedures and conduct such studies, but those processes are not included in the Tariff, PJM and the Transmission Owners should explain their existing processes and consider whether amendments are necessary to the Tariff to memorialize those processes and also address the concerns expressed herein. Otherwise, PJM should explain whether the Tariff remains just and reasonable without: (1) sufficiently clear and consistent provisions to evaluate the impact of providing the requested transmission service to Eligible Customers on behalf of large loads, including identifying the Direct Assignment Facilities and Network Upgrades necessary to provide such service reliably; (2) provisions to appropriately recognize within the transmission service study process the unique operational characteristics of large loads; (3) a study deadline of no more than 60-90 calendar days; or propose Tariff revisions establishing them.

64. Third, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks provisions addressing ongoing operational requirements for transmission customers taking transmission service on behalf of large loads. We are concerned that without such requirements the rates, terms, and conditions of transmission service may be unjust and unreasonable. The unique nature of these large loads creates challenges for operation of the transmission system and necessitates greater visibility and operational control when providing transmission service to transmission customers on behalf of large loads, without which the reliability of the transmission system could be at risk.¹⁵³ For example, we are concerned that PJM's Tariff does not require transmission customers to provide PJM hourly forecasts, telemetry data, and other data to ensure sufficient visibility or specify requirements for maintaining communication channels between PJM and the transmission customer on behalf of the large load. Additionally, we are concerned that the Tariff does not require transmission owners to install, and transmission customers to pay for, equipment to enable PJM to monitor large loads for impacts of, for example, fast-ramping load that may impact the transmission system too quickly to be captured by conventional data acquisition systems (e.g., the need for phasor

¹⁵² Several commenters support a 60-day timeline. *See, e.g.*, Constellation November 21 ANOPR Comments at 26; Critical Loop December 5 ANOPR Comments at 8; EDF Power November 21 ANOPR Comments at 16; Tract November 21 ANOPR Comments at 9. Other commenters note that SPP's HILL process has a 90-day timeline, or otherwise support a 90-day timeline. *See, e.g.*, AEMA November 21 ANOPR Comments at 3; Eolian December 5 ANOPR Comments at 27; Industrial Customers November 21 ANOPR Comments at 20; PJM November 21 ANOPR Comments at 7; SPP November 21 ANOPR Comments at 16-17.

¹⁵³ *E.g.*, ATC November 21 ANOPR Comments at 14; CAISO November 21 ANOPR Comments at 10 (citing NERC Characteristics and Risks of Large Loads); Herb Schrayshuen November 21 ANOPR Comments at 2-5.

measurement units or similar equipment). We are also concerned that the Tariff does not require the transmission customer to enable PJM to remotely disconnect large loads when necessary to maintain reliability of the transmission system, with the costs of such equipment directly assigned to the transmission customer, as well as the terms and conditions under which PJM may remotely disconnect the large load (e.g., emergency conditions, so that transmission equipment is not harmed). Further, we are concerned that the Tariff does not specify ramp rate or ride-through requirements with which the transmission customer taking transmission service on behalf of the large load must comply. Lastly, we are concerned that the Tariff does not specify requirements for necessary control technologies and/or protection systems that may be necessary to limit a transmission customer's withdrawals from the transmission system as appropriate.¹⁵⁴ PJM should explain whether the Tariff remains just and reasonable without these or other ongoing operational requirements as part of the rates, terms, and conditions of transmission service or propose Tariff revisions establishing necessary ongoing operational requirements.

65. Fourth, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks *pro forma* provisions in a transmission service agreement between PJM and the transmission customer taking transmission service on behalf of a large load to memorialize the above terms (e.g., equipment requirements, data requirements, remote disconnect capability). We are concerned that, without such *pro forma* provisions in a transmission service agreement between PJM and the transmission customer, PJM may be unable to enforce ongoing operational requirements for transmission customers taking transmission service on behalf of large loads. PJM should explain whether the Tariff remains just and reasonable without such *pro forma* provisions in a transmission service agreement, or propose revisions to include *pro forma* provisions memorializing the ongoing operational requirements in a transmission service agreement between PJM and the transmission customer.

B. Cost Shifting Risk Among Transmission Customers

66. We next preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks adequate mechanisms to mitigate the risk of cost shifting among transmission customers, which may result in unjust and unreasonable rates for transmission service. In particular, we are concerned about the apparent lack of: (1) transparency regarding the assignment of Network Upgrades, and their associated costs, that are needed to provide transmission service to Eligible Customers on behalf of large loads; and (2) a *pro forma* cost recovery agreement between PJM, the relevant

¹⁵⁴ Specifically, as discussed below, the Commission has found that such necessary control technologies and/or protection schemes may be appropriate where Eligible Customers are taking one of the new transmission services. *See infra* P 87.

transmission owner, and the Eligible Customer taking transmission service on behalf of large loads that help ensure that Eligible Customers bear the risk and are ultimately responsible for costs incurred to provide transmission service, including the cost of Network Upgrades.

67. We direct PJM and the Transmission Owners, to the extent the matters addressed herein implicate aspects of the Tariff over which they have the filing rights, to explain whether the Tariff remains just and reasonable without (1) robust, accurate, and systematic provision of data on PJM's website in a single location, and in an easily accessible format that is searchable and allows users to filter the data, regarding the cost for Network Upgrades needed to provide transmission service to Eligible Customers on behalf of large loads; and (2) a *pro forma* cost recovery agreement between PJM, the relevant transmission owner, and the Eligible Customer taking transmission service on behalf of a large load, or to propose Tariff revisions to provide additional transparency and establish such a *pro forma* cost recovery agreement. We encourage state regulators responsible for setting retail rates to provide input to PJM regarding their transparency needs.

1. Jurisdiction

68. The Commission has a duty to address the risk of cost shifting among transmission customers that may result in unjust and unreasonable transmission rates. As explained above, the Commission is obligated to ensure that the rates charged for jurisdictional transmission service—as well as any practice directly affecting such rates—are just and reasonable and not unduly discriminatory or preferential. With respect to the addition of large loads to the transmission system, the Commission has exclusive authority to ensure that transmission rates are just and reasonable. The costs of those upgrades to the transmission system (i.e., Network Upgrades) necessary to provide transmission service to Eligible Customers on behalf of large loads are inputs to jurisdictional transmission rates, and thus directly affect the Commission-jurisdictional rates paid by transmission customers. To fulfill its responsibility to ensure that transmission rates are just and reasonable, the Commission must act to address the risk of cost shifting among transmission customers due to (1) the process transmission providers and/or transmission owners use to evaluate the facilities needed, and the associated costs, for the provision of transmission service to Eligible Customers on behalf of large loads and (2) speculative transmission service requests by Eligible Customers on behalf of large loads that could result in unjust and unreasonable transmission rates.

69. In response to the ANOPR, many commenters raise concerns about the impact that large load additions can have on retail ratepayers, particularly the concern that other retail ratepayers may be forced to subsidize Network Upgrades needed to add large loads to the

transmission system.¹⁵⁵ While we appreciate and are similarly concerned about this issue, the Commission is limited to addressing jurisdictional transmission rates and as such, we do so herein. As the Commission has explained, states determine how Commission-approved rates are collected among the relevant retail consumers along with the rates for state-jurisdictional matters.¹⁵⁶ Specifically, states have authority over how the wholesale costs of providing electricity, including transmission of such electricity, to those retail customers are recovered through retail rates.¹⁵⁷ We are encouraged by efforts taken by states to reform retail tariffs to address the potential for retail cost shifting as large loads come online,¹⁵⁸ as well as voluntary efforts by transmission owners to protect retail ratepayers through cost recovery agreements with large loads.¹⁵⁹ We are also encouraged by the execution of the President's Ratepayer Protection Pledge, through which data center developers have committed to shield retail ratepayers from increased electricity prices.¹⁶⁰

70. We expect that the additional cost transparency measures proposed in the following section will give state public utility commissions and other state regulators the information necessary to allow them to understand which transmission costs are caused by which transmission customers, so that they can sub-allocate these costs to the appropriate retail customers. Indeed, the Commission's objective in this proceeding is to respect the cooperative federalism approach established under the FPA. Specifically, one of the benefits of providing transparency on the costs of Network Upgrades necessary to provide transmission service to Eligible Customers on behalf of large loads is so that state regulators can use that information to protect residential and small commercial customers

¹⁵⁵ See, e.g., Illinois AG November 21 ANOPR Comments at 11-12; Missouri Commission November 21 ANOPR Comments at 11; OMS November 21 ANOPR Comments at 4.

¹⁵⁶ PJM Show Cause Order, 190 FERC ¶ 61,115 at P 167.

¹⁵⁷ *Id.* P 68.

¹⁵⁸ See, e.g., Pennsylvania Commission November 21 ANOPR Comments at 7-8; Maryland Commission November 21 ANOPR Comments at 2; Virginia Commission November 21 ANOPR Comments at 4-5

¹⁵⁹ See, e.g., *Commonwealth Edison Co.* 194 FERC ¶ 61,106; *Commonwealth Edison Co.*, 194 FERC ¶ 61,109; *Commonwealth Edison Co.*, 194 FERC ¶ 61,110; *Commonwealth Edison Co.*, 194 FERC ¶ 61,113 (2026); *PECO Energy Co.*, 193 FERC ¶ 61,148; *Dayton Power & Light Co.*, 192 FERC ¶ 61,103; *Dayton Power & Light Co.*, 189 FERC ¶ 61,220 (2024).

¹⁶⁰ Proclamation No. 11014, 91 Fed. Reg. 11439 (Mar. 4, 2026).

by incorporating those costs into the retail rates as they see fit given their authority to set rates for different classes of retail customers. We encourage state public utility commissions, state regulators, and state consumer advocates to submit comments explaining whether this information is sufficient and granular enough or to submit comments explaining precisely which additional information on transmission cost allocation may be needed to inform proper state-jurisdictional cost allocation.

2. Additional Cost Transparency

71. We preliminarily find that PJM's Tariff appears to be unjust and unreasonable or unduly discriminatory or preferential because it does not contain provisions requiring the provision of data on PJM's website in a single location, and in an easily accessible format that is searchable and allows users to filter the data, on transmission service requested by Eligible Customers on behalf of large loads, for Network Upgrades evaluated in the local transmission planning process that are needed to provide transmission service to Eligible Customers on behalf of those large loads, and the costs for those Network Upgrades. We preliminarily find that cost transparency measures are needed to provide stakeholders with sufficient information and visibility regarding the Network Upgrades, and their associated costs, needed to provide transmission service to Eligible Customers on behalf of large loads.

72. As discussed above, Network Upgrades needed to accommodate a new transmission service request or designation of new network load may be designated as local transmission facilities (i.e., Supplemental Projects) or contribute to regional transmission system needs and be addressed by a Required Transmission Enhancement in the RTEP. PJM's Tariff Schedule 12 Appendix and Appendix A include the cost responsibility assignments for regional transmission projects selected through the RTEP process. In addition, Attachment M-3 of PJM's Tariff provides procedures for stakeholder review and comment on Supplemental Projects identified through transmission owners' local transmission planning process in the Transmission Expansion Advisory Committee (230 kV or above) and Subregional RTEP Committee (below 230 kV) and as part of a transmission owner's Local Plan, before the Local Plan is submitted for integration into the RTEP.¹⁶¹ PJM's website also includes a list of Required Transmission Enhancements and Supplemental Projects with their project status, cost, and cost allocation.¹⁶²

¹⁶¹ See PJM Tariff, attach. M-3, § (c) (Procedures for Review of Attachment M-3 Projects) (1.0.0).

¹⁶² PJM, *Project Status & Cost Allocation*, <https://www.pjm.com/planning/m/project-construction>.

73. However, PJM's Tariff does not appear to require that information identifying the Network Upgrades needed to provide transmission service to Eligible Customers on behalf of large loads and the costs of those Network Upgrades determined through local transmission planning processes be readily available on PJM's website in a single location, and in an easily accessible format that is searchable and allows users to filter the data. We acknowledge that PJM's website provides information concerning certain transmission projects, including Supplemental Projects, such as project status, cost, cost allocation, and the type of equipment and upgrade, and includes the primary driver for each transmission project (i.e., load growth), but these postings do not appear to be specific to transmission projects needed to provide transmission service to Eligible Customers on behalf of large loads. The speed and scale with which Eligible Customers are seeking transmission service on behalf of large loads makes it difficult for interested parties, including transmission customers and state regulators, to accurately assess which transmission costs are driven by requests for transmission service by Eligible Customers to serve large loads. Further, as PJM acknowledges, it forecasts significant peak load growth, but there is a large cone of uncertainty around the trajectory and amplitude of future demand growth.¹⁶³ We are concerned that the potentially speculative nature of requests for transmission service by Eligible Customers on behalf of large loads,¹⁶⁴ the speed and scale with which large loads are seeking to be added to the transmission system, the projected need for significant Network Upgrades to provide transmission service to Eligible Customers on behalf of large loads, and the lack of centralized information on the associated transmission costs in PJM hamper the ability of the Commission and stakeholders (including transmission customers and state regulators¹⁶⁵) to understand and accurately assess the relationship between the addition of large loads to the transmission system and wholesale transmission costs.

¹⁶³ See PJM Board Letter at 1.

¹⁶⁴ See *supra* P 56.

¹⁶⁵ See Transcript, NARUC Collaborative, Docket No. AD24-7-000, at 16-17 (Feb. 11, 2026) (Chair Bagot, Virginia) (asserting that additional transparency at the RTO level would help the states get the information they need to "identify . . . that bucket of costs" related to large load-driven transmission costs), 19 (Commissioner Chattopadhyay, New Hampshire) (noting the need for "all parties to be able to see things transparently" with respect to wholesale transmission costs), 35-37 (Chair Martz, Iowa) (raising concern that currently RTOs/ISOs do not have to clearly explain when a "bucket of costs is specifically for this large load" and noting that "if we, at the state level, can't see the driver [of transmission costs], we can't assign the cost to the causer[,] [a]nd so we need that clarity"), 69-70 (Chair Myers, Arizona) ("[B]eing able to allocate the large load costs to the correct bucket when it gets to the states is kind of a top priority.").

74. We are concerned that without sufficient transparency regarding the Network Upgrades, and their associated costs, needed to provide transmission service to Eligible Customers on behalf of large loads, stakeholders may lack information and visibility regarding the costs driven by large load additions. We preliminarily find that, for Network Upgrades evaluated in the local transmission planning process¹⁶⁶ that are needed to provide transmission service to Eligible Customers on behalf of large loads, PJM must provide clear, timely, and detailed information regarding the extent to which requests for transmission service by Eligible Customers on behalf of large loads necessitate Network Upgrades to accommodate the transmission service to Eligible Customers on behalf of large loads, as well as the costs of those Network Upgrades.

75. We note that centralized information regarding Network Upgrades needed to accommodate requests for transmission service by Eligible Customers on behalf of large loads would also help inform stakeholders at the state and local level to address affordability and other challenges posed by the integration of large loads. Indeed, commenters state that the opaque nature of requests for transmission service by Eligible Customers on behalf of large loads, and the associated Network Upgrades required to provide that transmission service, prevent wholesale and retail customers, states, and other stakeholders from understanding such costs.¹⁶⁷

¹⁶⁶ Our concern with transparency regarding Network Upgrades needed to provide transmission service to Eligible Customers on behalf of large loads, as well as the costs of such upgrades, is limited to Network Upgrades planned through the local transmission planning process. While we acknowledge that in Order No. 890, the Commission adopted requirements for RTOs/ISOs, as well as for transmission owners to the extent that they perform transmission planning within an RTO/ISO, to have open and transparent transmission planning processes, there are additional requirements that apply to regional transmission planning processes (that do not apply to local transmission facilities) and thus is relevant to the distinction here. Specifically, under Order No. 1000, public utility transmission providers, including RTOs/ISOs, must evaluate as part of their regional transmission planning process whether there are transmission facilities that more efficiently or cost-effectively meet the transmission planning region's identified transmission needs. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 11.

¹⁶⁷ *See* OCC November 21 ANOPR Comments at 3 (“Consumers, state advocates and state regulatory commissions have a right to know which entities are seeking large-load interconnections, the nature of the requested service, and how related costs could flow through to transmission and distribution rates.”); U.S. House of Representatives Committee on Energy and Commerce Ranking Members November 21 ANOPR Comments at 2 (urging the Commission to “require sufficient transparency from grid operators so it can determine which specific large load facilities are responsible for grid upgrade needs”); *see also* CPUC November 21 ANOPR Comments at 16-17

76. Accordingly, we preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it does not require the provision of data on PJM's website in a single location, and in an easily accessible format that is searchable and allows users to filter the data, that identifies the Network Upgrades that are needed to accommodate requests for transmission service by Eligible Customers on behalf of large loads, and the costs of those Network Upgrades. PJM should explain whether the Tariff remains just and reasonable without provisions that would require PJM and the Transmission Owners to publicly post and regularly update data that details: (1) the aggregate amounts of proposed large load additions in PJM's footprint, including the aggregate amounts in each transmission pricing zone; (2) the planned Network Upgrades needed to provide transmission service to Eligible Customers on behalf of large loads, identified by type of equipment and Network Upgrade (e.g., new substation, reconductoring, a new high-voltage transmission line) for each transmission service request; and (3) cost estimates for those Network Upgrades; or propose such Tariff revisions. PJM and the Transmission Owners should also consider what other data related to transmission costs resulting from the provision of transmission service to Eligible Customers on behalf of large loads would be useful to include on PJM's website. To the extent there are concerns about data confidentiality, PJM and the Transmission Owners should consider whether there are ways to mitigate those concerns while still providing the necessary transparency.

3. Cost Recovery Agreements

77. We next preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it lacks adequate mechanisms to mitigate the risk of cost shifting among transmission customers, which may result in unjust and unreasonable rates for transmission service. In particular, we are concerned about the apparent lack of a *pro forma* cost recovery agreement between PJM, the relevant transmission owner, and the Eligible Customer taking transmission service on behalf of large loads that help ensure that Eligible Customers bear the risk and are ultimately responsible for costs incurred to provide transmission service, including the cost of Network Upgrades.

78. Several commenters discuss the risk of cost shifting among transmission customers that could result from transmission service requests by Eligible Customers on behalf of large loads.¹⁶⁸ Commenters also argue that retail-level large load tariffs do not

(asserting that the public posting of large load cost responsibility determinations would improve transparency, to the benefit of businesses and ratepayers).

¹⁶⁸ See, e.g., Buckeye November 21 ANOPR Comments at 8-13; APPA November 21 ANOPR Comments at 6 ("Wholesale transmission customers in particular could be left shouldering massive costs if new large loads do not ultimately attain or maintain the level of electricity demand that is being forecasted."); NRECA

protect wholesale transmission customers from cost shifting.¹⁶⁹ Specifically, commenters in the record contend that, while a retail-level large load tariff protects the load serving entity taking wholesale transmission service and its retail customers, it fails “to provide any mechanism to protect *other wholesale transmission customers*” from stranded transmission costs.¹⁷⁰ The Kansas Commission states that while its Large Load Power Services rate plan that requires large loads to make minimum payments toward transmission costs protects retail ratepayers from large-load driven transmission costs, it cannot protect against cost shifting associated with regional transmission buildout where “the large loads that formed the basis for the [regional] transmission plans do not materialize, leaving only existing customers to pay for generational expansions of the transmission grid.”¹⁷¹ TAPS contends, moreover, that it is not sufficient for the Commission to rely on transmission owners to voluntarily file cost recovery agreements to protect transmission customers from cost shifting for Network Upgrades.¹⁷²

79. We are likewise concerned that there may be speculative transmission service requests by Eligible Customers on behalf of large loads that could result in cost shifting among transmission customers, which may lead to unjust and unreasonable increases in jurisdictional transmission rates. When a transmission owner constructs Network Upgrades to accommodate an Eligible Customer’s request for transmission service on behalf of a large load, those transmission costs will be included in the transmission owner’s transmission revenue requirement. If, however, the Eligible Customer takes less transmission service than anticipated because the large load operates at a lower demand

November 21 ANOPR Comments at 21 (noting the risk that other transmission customers could bear stranded upgrade costs caused by large loads that they cannot absorb); TAPS November 21 ANOPR Comments at 22-24; California DWR November 21 ANOPR Comments at 8.

¹⁶⁹ TAPS November 21 ANOPR Comments at 26 (“[A] number of state commissions are moving forward with retail large load tariffs, which provide for varying protections, but may not require the revenues and minimum demand levels to be included in wholesale transmission rates.”); Buckeye November 21 ANOPR Comments at 14-16; Kansas Commission November 21 ANOPR Comments at 15-16.

¹⁷⁰ Buckeye November 21 ANOPR Comments at 14-15; *see* TAPS November 21 ANOPR Comments at 26-27 & nn.50-51.

¹⁷¹ Kansas Commission November 21 ANOPR Comments at 11-12.

¹⁷² TAPS November 21 ANOPR Comments at 25-26 (noting that AES Ohio “committed to reflecting the payments it received from the data center in its Commission-jurisdictional transmission revenue requirement so that other customers are protected,” in a Construction Service Agreement with Amazon).

than anticipated or fails to materialize at all, other transmission customers may see an increase in transmission rates. In such a situation, those other transmission customers may have to pay for potentially unnecessary Network Upgrades that they neither caused the need for nor benefit commensurately from. In other words, this introduces the risk that costs may be unfairly shifted to other transmission customers, which may result in those costs then being passed through to residential customers, among others.

80. PJM's Tariff does not require cost recovery agreements between PJM, the relevant transmission owner, and the Eligible Customer taking transmission service on behalf of a large load. Such agreements would help ensure that the Eligible Customer makes a minimum contribution to the transmission owner's transmission revenue requirement commensurate with the costs incurred to provide the requested transmission service, including the costs of any needed Network Upgrades. Absent such cost recovery agreements, we are concerned that there is no mechanism to help ensure that Eligible Customers taking transmission service on behalf of large loads (as opposed to other transmission customers) bear the risk of, and are ultimately responsible for, the costs incurred to provide them with the requested transmission service, including the costs of any needed Network Upgrades.

81. Accordingly, we preliminarily find that, in order to prevent unjust and unreasonable cost shifting among transmission customers, it appears necessary for PJM, the relevant transmission owner, and the Eligible Customer taking transmission service on behalf of a large load to enter into a cost recovery agreement that requires the Eligible Customer to make a minimum contribution toward the transmission owner's transmission revenue requirement, if the Eligible Customer ultimately takes less transmission service than anticipated because the large load does not materialize as planned or is not developed at all. We preliminarily find that such cost recovery agreements are necessary to help ensure that the Eligible Customer is responsible for timely paying the costs of large load-driven transmission (i.e., the costs incurred to provide them with the requested transmission service, including the costs of any needed Network Upgrades), rather than having those costs paid by other transmission customers that neither caused the need for nor benefit commensurately from those Network Upgrades.¹⁷³ Our preliminary finding is not intended to alter or call into question existing regional cost allocation methods for Network Upgrades, but instead is focused on helping to prevent cost shifting among transmission customers.

82. We note that several transmission owners and large load customers have filed cost recovery agreements (Transmission Security Agreements or Construction Service Agreements) with the Commission that guarantee minimum contributions from a large

¹⁷³ See, e.g., *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); *Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

load customer (rather than from the Eligible Customer taking transmission service on behalf of the large load customer) to the transmission owner's transmission revenue requirement.¹⁷⁴ Although we decline to preliminarily find that cost recovery agreements between the transmission owner and the large load customer (rather than the Eligible Customer) are necessary to ensure just and reasonable transmission rates, we continue to find that such agreements directly affect Commission-jurisdictional transmission rates. Therefore, to the extent a transmission owner and a large load customer enter into a cost recovery agreement (whether voluntarily or pursuant to state law) through which the large load customer guarantees contributions to the transmission owner's Commission-jurisdictional transmission revenue requirement, we find that such an agreement should be filed with the Commission.¹⁷⁵ To reduce duplicative credit requirements and transaction costs, we direct further briefing on whether it would be appropriate for such an agreement to substitute for the requirement on the Eligible Customer to enter into a cost recovery agreement with the transmission owner, if the agreement with the large load customer provided comparable or greater protection against cost shifting among transmission customers than an agreement between the transmission owner and the Eligible Customer would.

83. In addition to our preliminary finding that PJM's Tariff is unjust and unreasonable because it lacks a *pro forma* cost recovery agreement of this type, we also preliminarily find that the minimum contribution required pursuant to such an agreement should be based on the level of jurisdictional transmission service (in MW) requested by the Eligible Customer on behalf of the large load. That figure is in turn tied to how PJM and/or Transmission Owners will study the requested transmission service and determine any necessary Network Upgrades that must be developed to provide the requested transmission service. We note, however, that there may be other just and reasonable methods for determining this minimum contribution, including methods that account for potential timing differences between when costs are incurred to develop needed Network Upgrades and the pace at which the large load ramps toward energizing at its full level of requested service. We further preliminarily find that the cost recovery agreement should include a credit support (or other financial security) requirement sufficient to secure the obligations of the Eligible Customer taking transmission service on behalf of a large load to pay the amounts owed pursuant to the cost recovery agreement. We find that a cost recovery agreement with a specified minimum financial contribution and financial security sufficient to secure such contribution is necessary to mitigate cost shifting if the

¹⁷⁴ See *supra* note 159.

¹⁷⁵ We emphasize that this finding is in no way intended to preempt or interfere with the ability of states to implement ratepayer protection measures designed to mitigate cost shifting among retail customers, such as through state-jurisdictional large load tariffs.

Eligible Customer ultimately takes less transmission service than anticipated because the large load does not materialize as planned or is not developed at all. We preliminarily find that an Eligible Customer may include a credit support or other financial security posted by a large load as part of a retail agreement to avoid creating duplicative credit support requirements. PJM should explain why such a *pro forma* cost recovery agreement is not necessary to ensure just and reasonable rates, or propose such a *pro forma* cost recovery agreement. To the extent that stakeholders believe that other mechanisms could address our cost shifting concerns, we seek further briefing as discussed below.¹⁷⁶

84. Lastly, we expect that any payments made by an Eligible Customer to a transmission owner pursuant to such a cost recovery agreement (or by a large load to a transmission owner pursuant to other voluntary agreement) will be appropriately credited toward transmission owners' transmission revenue requirements consistent with the Commission's cost-of-service regulations.¹⁷⁷ We preliminarily find that it appears reasonable for filers of formula rates to provide a separate workpaper in the annual informational filing describing how any payments made pursuant to a cost recovery agreement are reflected in the transmission owner's transmission formula rate.

C. Extending New Transmission Services to Eligible Customers Taking Service on Behalf of Flexible Large Loads

85. In response to the ANOPR, a number of commenters argue that certain large loads are able to limit their withdrawals from the transmission system under certain conditions. Namely, commenters observe that flexible large loads¹⁷⁸ can quickly and verifiably adjust their consumption in response to system conditions or price signals.¹⁷⁹ Commenters in the ANOPR also observe that, where load studies and system planning consider the flexible nature of large loads, flexible large loads can potentially defer or reduce the need

¹⁷⁶ See *infra* P 107.

¹⁷⁷ See 18 C.F.R. pt. 101 (2025).

¹⁷⁸ For purposes of this order, "flexible" large loads are a subset of large loads, as used in this order, that are not co-located with generation, but are willing and able to limit their energy withdrawals from the transmission system under certain conditions.

¹⁷⁹ See, e.g., AEMA November 21 ANOPR Comments at 1-2; Land Trust Alliance November 21 ANOPR Comments at 10; California DWR November 21 ANOPR Comments at 5; CEBA November 21 ANOPR Comments at 14-15; ClearPath November 21 ANOPR Comments at 2-4; Digital Energy Council November 21 ANOPR Comments at 1; EDF Power November 21 ANOPR Comments at 4; Emerald November 21 ANOPR Comments at 2; Verrus November 21 ANOPR Comments at 4.

for Network Upgrades, among other potential benefits.¹⁸⁰ In recognition of this flexibility, many commenters support new transmission services that reflect the operational capabilities of flexible large loads, including interim NITS while Network Upgrades are constructed, and non-firm transmission service.¹⁸¹

86. We preliminarily find that PJM's Tariff appears to be unjust and unreasonable because it does not include transmission services that reflect Eligible Customers taking transmission service on behalf of flexible large loads that are willing and able to limit their use of the transmission system under certain conditions. The transmission services available to Eligible Customers, including on behalf of flexible large loads, in PJM are NITS and firm and non-firm Point-to-Point Transmission Service.¹⁸² While these remain just and reasonable options for an Eligible Customer to take on behalf of a flexible large load, based on the record before us, we preliminarily find that new transmission services should be available to reflect the operational reality that large loads may use the transmission system to differing extents and certain large loads are willing and able to limit their use of the transmission system under certain conditions.¹⁸³ The Commission found that Eligible Customers taking transmission service on behalf of Eligible Load should be allowed to choose a transmission service that aligns with their use of the transmission system and therefore aligns the charges for service with the benefits received.¹⁸⁴ As the record suggests, Eligible Customers taking transmission service on behalf of flexible large load also may be willing and able to limit their use of the transmission system under certain conditions. As recognized in the ANOPR record, load

¹⁸⁰ See, e.g., AEMA November 21 ANOPR Comments at 5; ELCON November 21 ANOPR Comments at 9; Emerald November 21 ANOPR Comments at 6-7; Institute for Progress November 21 ANOPR Comments at 11; Land Trust Alliance November 21 ANOPR Comments at 10; LS Power November 21 ANOPR Comments at 5; Microsoft November 21 ANOPR Comments at 10-11; National Grid November 21 ANOPR Comments at 19-20; OMS November 21 ANOPR Comments at 13-14; Southeast PIOs November 21 ANOPR Comments at 50.

¹⁸¹ See, e.g., Constellation November 21 ANOPR Comments at 24-25; Calibrant November 21 ANOPR Comments at 2-4; Critical Loop November 21 ANOPR Comments at 2; Digital Power Network November 21 ANOPR Comments at 3; PIOs November 21 ANOPR Comments at 27-28; Splight November 21 ANOPR Comments at 3-4.

¹⁸² See *supra* P 19 (describing existing transmission services in PJM).

¹⁸³ See *supra* P 85.

¹⁸⁴ PJM Co-Location Order, 193 FERC ¶ 61,217 at P 199; PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209 at P 103.

flexibility can avoid inefficient and costly transmission system build-out.¹⁸⁵ In addition, transmission services that reflect that flexible large loads are willing and able to limit their withdrawals from the transmission system under certain conditions could help timely interconnect flexible large loads.¹⁸⁶ Entities in the PJM footprint acknowledge the importance of facilitating load flexibility.¹⁸⁷

87. Therefore, we are concerned that PJM's Tariff does not include transmission services that reflect the use of the transmission system by Eligible Customers on behalf of flexible large load, on both an interim and permanent basis. PJM should explain whether the Tariff remains just and reasonable without the transmission services described by the Commission in the PJM Co-Location Order being available to Eligible Customers taking transmission service on behalf of flexible large loads, or propose appropriate Tariff revisions. Specifically, PJM should explain whether the Tariff remains just and reasonable without (1) an interim non-firm network transmission service while Network Upgrades are being constructed (i.e., interim NITS) and (2) permanent firm and non-firm contract demand transmission services (transmission service up to a specified MW quantity, i.e., the contract level, on a firm or non-firm basis).¹⁸⁸ Finally, we note that the Commission has found it just and reasonable that, in order for an Eligible Customer to

¹⁸⁵ See *supra* P 85; see also PJM Co-Location Order, 193 FERC ¶ 61,217 at PP 160, 177, 199 (finding that new transmission service options reflect a co-located load's ability to limit withdrawals from the transmission system and potentially avoid costly and inefficient transmission system buildout that may not be necessary).

¹⁸⁶ See *supra* P 85; see also PJM Co-Location Order, 193 FERC ¶ 61,217 at PP 201 (finding that the interim, non-firm transmission service will facilitate the "timely" provision of transmission service and that "[t]his willingness to curtail would potentially allow them to obtain service more quickly"), 205 (recognizing that parties argue that co-located loads may be able to receive transmission service faster with use of a new, limited transmission service product than they would if they selected NITS, to the extent that providing NITS would require Network Upgrades that the limited transmission service would not).

¹⁸⁷ See, e.g., Constellation November 21 ANOPR Comments at 23-24; Load Flexibility Parties November 21 ANOPR Comments at 2-5; State Entities November 21 ANOPR Comments at 4.

¹⁸⁸ In an order also issued today, the Commission established as just and reasonable certain rates, terms, and conditions for the new transmission services directed in the PJM Co-Location Order, which include portions of PJM's and the Transmission Owners' proposals submitted in the briefs, and directed further compliance filings. See *generally* PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209.

take interim NITS, firm contract demand transmission service, and non-firm contract demand transmission service, an Eligible Customer must have necessary control technologies and/or protection systems, which may include a special protection scheme, to limit its energy withdrawals to its approved level.¹⁸⁹

D. Interconnection Customers Serving Electrically Proximate Large Load and Co-Located Load

88. In response to the ANOPR, a number of commenters agree that the ability to study new load and new generation together, when physically or electrically proximate, presents system benefits and can help address the challenges posed by large load additions.¹⁹⁰ Commenters argue that studies that consider large load and generation together present a more complete picture of the grid and can enable the identification of more accurate, efficient, and cost-effective transmission solutions by minimizing system impacts.¹⁹¹ As a result, this can speed up the interconnection process for both large loads and generation, and shorten energization timelines,¹⁹² which commenters contend reduces uncertainty for both parties¹⁹³ and “is necessary to match the pace of AI innovation in the United States.”¹⁹⁴ CEBA also highlights that cost and timeline factors drive developers to submit multiple requests for price and timing discovery, which inflates queue volumes,

¹⁸⁹ PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209 at P 480.

¹⁹⁰ See e.g., DCC November 21 ANOPR Comments at 5-6; DTE November 21 ANOPR Comments at 11; Google November 21 ANOPR Comments at 7; International Energy Credit Association November 21 ANOPR Comments at 10; Terraflux November 21 ANOPR Comments at 1.

¹⁹¹ AEU November 21 ANOPR Comments at 13; ClearPath November 21 ANOPR Comments at 4; DCC November 21 ANOPR Comments at 5; DTE November 21 ANOPR Comments at 8-11; ENGIE November 21 ANOPR Comments at 6; Entergy November 21 ANOPR Comments at 5; Geronimo November 21 ANOPR Comments at 17-18; Information Technology Industry Council November 21 ANOPR Comments at 2.

¹⁹² DCC November 21 ANOPR Comments at 5; DTE November 21 ANOPR Comments at 8-11; Information Technology Industry Council November 21 ANOPR Comments at 2; Microsoft November 21 ANOPR Comments at 8-9; Verrus December 5 ANOPR Comments at 9.

¹⁹³ ClearPath November 21 ANOPR Comments at 4; CEBA November 21 ANOPR Comments at 8.

¹⁹⁴ Microsoft November 21 ANOPR Comments at 8-9.

distorts demand and supply forecasts, and causes significant delays when projects withdraw late after finding costs or energization timelines uneconomic.¹⁹⁵ Other benefits to a joint study identified by commenters include improving load forecasting and siting decisions¹⁹⁶ and reducing the need for critical supply chain components.¹⁹⁷

89. Commenters contend that current generator interconnection study processes may not adequately capture generation and load, including by failing to model known electrically proximate large load in base case assumptions, which may result in inaccurate studies and inefficient system build-out.¹⁹⁸ For example, Eolian states that in its experience developing a project in PJM, the failure of the generator interconnection study process to reflect reasonably expected load conditions on the grid models triggered overly costly Network Upgrades and caused the cancellation of generation project that could have reliably served adjacent load growth.¹⁹⁹

90. Commenters in the ANOPR proceeding argue that the current state of the generator interconnection queue is not meeting the expeditious time frame needed to match the pace of large load additions and ensure the safe and reliable interconnection of these loads.²⁰⁰ For example, Oracle states that one of the most significant and widespread delays it encounters when siting data centers in the U.S. is access to sufficient energy.²⁰¹ Similarly, Helion contends that more than half of U.S. developers now identify

¹⁹⁵ CEBA November 21 ANOPR Comments at 8.

¹⁹⁶ ELCON November 21 ANOPR Comments at 5; Maryland Commission November 21 ANOPR Comments at 6-7.

¹⁹⁷ AEU November 21 ANOPR Comments at 13.

¹⁹⁸ Base Power November 21 ANOPR Comments at 7; Eolian November 21 ANOPR Comments at 18-19; Eolian May 19 ANOPR Comments at 2; Longroad November 21 ANOPR Comments at 8.

¹⁹⁹ Eolian May 19 ANOPR Comments at 10.

²⁰⁰ *See, e.g.*, AEP December 5 ANOPR Comments at 1; DCC November 21 ANOPR Comments at 8; esVolta November 21 ANOPR Comments at 11-12; Oracle May 1 ANOPR Comments at 4.

²⁰¹ Oracle November 21 ANOPR Comments at 1.

interconnection delays as the single biggest barrier to adding new generation capacity.²⁰² Commenters contend that if large load interconnection proceeds more quickly than new generation can come online, the result could be price increases for consumers.²⁰³

91. A number of commenters support expedited interconnection studies for new generation paired with load.²⁰⁴ Some commenters argue that one solution to generator interconnection delays may be the creation of time-limited or conditional interconnection service for generators serving large loads, which could require less time for initial generator interconnection studies and improve speed to power.²⁰⁵ For example, several commenters express support for SPP's HILLGA proposal as a model and urge the Commission to establish nationwide rules similar to that approach.²⁰⁶ Other commenters suggest reforms to expedite studies for new generation paired with large loads at existing points of interconnection that have already been studied, arguing it is unjust and unreasonable not to fully utilize existing infrastructure and proven reliability paths while new load waits for service.²⁰⁷

1. Jurisdiction

92. The Commission's statutory authority includes jurisdiction over the wholesale sale and transmission of electricity in interstate commerce, including the facilities used for

²⁰² Helion November 21 ANOPR Comments at 1 (citing Third Way, *Picking Up the PACE: A Comprehensive Analysis of Available Pathways to Accelerating Clean Energy (PACE)* (Nov. 2025)).

²⁰³ AEP December 5 ANOPR Comments at 1-2; OPSI November 21 ANOPR Comments at 6-7, 11.

²⁰⁴ See, e.g., DTE November 21 ANOPR Comments at 8; ENGIE November 21 ANOPR Comments at 4; International Energy Credit Association November 21 ANOPR Comments at 8; Meta November 21 ANOPR Comments at 5-6; Ohio FEA November 21 ANOPR Comments at 5.

²⁰⁵ AEP December 5 ANOPR Comments at 12; AEU November 21 ANOPR Comments at 13; Google December 5 ANOPR Comments at 15; see also Duke November 21 ANOPR Comments at 21-22.

²⁰⁶ AEP December 5 ANOPR Comments at 4; Crusoe December 5 ANOPR Comments at 7; Enchanted Rock November 21 ANOPR Comments at 4; Google November 21 ANOPR Comments at 7; GridStor November 21 ANOPR Comments at 5; Verrus November 21 ANOPR Comments at 9.

²⁰⁷ Constellation June 5 ANOPR Comments at 8-9.

such sale and transmission.²⁰⁸ The Commission also has exclusive jurisdiction to regulate the procedures and agreements applicable to generating facilities seeking to interconnect to a Commission-jurisdictional distribution facility or transmission facility.²⁰⁹ In the PJM Co-Location Order, the Commission observed that a generator's interconnection to the interstate transmission system "does not fall outside of the Commission's jurisdiction merely because there is [c]o-[l]ocated [l]oad behind the generator's point of interconnection."²¹⁰ By the same token, the Commission retains jurisdiction over a generator's interconnection even where the generator plans to serve an electrically proximate large load.

93. We recognize that states have exclusive authority over resource planning and the generation mix within their boundaries.²¹¹ Nothing about our preliminary finding here, however, intrudes or is intended to intrude on that exclusive authority. Rather, we preliminarily find that it is necessary and appropriate to exercise our exclusive jurisdiction over generator interconnection to ensure the availability of generator interconnection processes specifically tailored to the unique operational characteristics of generating facilities dedicated to serving electrically proximate large loads and co-located loads, as defined below. The Commission has exercised this jurisdiction previously in requiring generator interconnection services that allow certain generating facilities to interconnect more quickly through the use of provisional interconnection service and surplus interconnection service,²¹² and has approved interconnection processes that allow

²⁰⁸ 16 U.S.C. § 824(b)(1).

²⁰⁹ *Id.*; *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d at 1280-82 (affirming Order No. 2003 and observing that "interconnections appear to be relationships between parties with respect to electricity flowing over facilities. . . By establishing standard agreements [the Commission] has exercised its jurisdiction over the *terms* of those relationships."); *see Pac. Gas & Elec. Co.*, 115 FERC ¶ 61,193 at P 36 ("[I]nterconnection is part and parcel of transmission of electric energy in interstate commerce, and thus interconnection service is part and parcel of jurisdictional transmission service.").

²¹⁰ PJM Co-Location Order, 193 FERC ¶ 61,217 at P 171.

²¹¹ *See, e.g., Citizens Action Coal. of Ind., Inc. v. FERC*, 125 F.4th at 238 (citing 16 U.S.C. § 824(b)(1)).

²¹² *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 163 FERC ¶ 61,043, at PP 438, 467 (2018), *order on reh'g & clarification*, Order No. 845-A, 166 FERC ¶ 61,137, *order on reh'g & clarification*, Order No. 845-B, 168 FERC ¶ 61,092 (2019); Order No. 2023, 184 FERC ¶ 61,054 at P 1436; *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

certain generating facilities to interconnect more quickly by replacing a retiring existing generating facility.²¹³

2. Definitions

94. For purposes of this order, it appears to be reasonable to use the term “electrically proximate large load” to mean a large load, as defined in this order,²¹⁴ that is sufficiently electrically close to the interconnection customer’s requested point of interconnection, such that the impact on the transmission system of the combination of the generating facility and the load, with the exception of the transmission facilities between the two, will be effectively the same as if they were located at the same substation (e.g., large load that is located no more than two substations away from the generating facility). We will consider proposed revisions to this definition that ensure it is appropriately tailored to PJM’s transmission system.

3. Tariff Provisions

95. We preliminarily find that PJM’s Tariff appears to be unjust and unreasonable because it does not contain provisions allowing an interconnection customer to seek the generator interconnection service(s) that reflects the operational dynamics of serving either: (1) an electrically proximate large load; or (2) a co-located load, as defined in the PJM Co-Location Order,²¹⁵ that has a high peak load (i.e., large co-located loads that are 50 MW or greater).²¹⁶ Specifically, we preliminarily find that PJM’s Tariff appears to be unjust and unreasonable because it lacks a generator interconnection study process and/or generator interconnection service to reflect an interconnection customer’s commitment in an interconnection agreement to limit the generating facility’s output to minimize the impact on the transmission system while serving an electrically proximate large load or large co-located load. We are concerned that PJM’s Tariff lacks, for example, generator interconnection study procedures and generator interconnection services that reflect (a) an interconnection customer’s commitment in an interconnection agreement to limit a generating facility’s output to match the hourly forecast of an electrically proximate large load or large co-located load; and/or (b) a generating facility with necessary control technologies and/or protection systems, which may include a special protection

²¹³ See, e.g., *PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,079 (2026); *Midcontinent Indep. Sys. Operator Inc.*, 167 FERC ¶ 61,146 (2019).

²¹⁴ See *supra* P 58.

²¹⁵ PJM Co-Location Order, 193 FERC ¶ 61,217 at P 164.

²¹⁶ We note that generator interconnection service in and of itself does not convey transmission service.

scheme,²¹⁷ that ensure that the injection does not exceed the limit in the existing or new interconnection agreement. Where a generating facility's output is matched to the demand of the electrically proximate large load or large co-located load or if the generating facility's output is limited to ensure no new injection, the impacts to the transmission system of interconnecting the generating facility to serve that electrically proximate large load or large co-located load may be limited,²¹⁸ thereby potentially reducing the need for Network Upgrades, which can accelerate the generator interconnection process.²¹⁹ In the absence of Tariff provisions accounting for these operational dynamics when an interconnection customer's generating facility is serving electrically proximate large loads or large co-located loads, new shovel-ready generating facilities may face unnecessary delays in reaching commercial operation under current generator interconnection processes and will be unable to serve the immediate demand of new large loads or large co-located loads.²²⁰

²¹⁷ PJM Co-Location Rehearing Order, 195 FERC ¶ 61,209 at P 480.

²¹⁸ In other words, because the generating facility and load are located so closely on the transmission system, if the generating facility's output matches the load's demand, then the transmission provider would need to study only the local impacts because the impact on the transmission system of the combination of the generating facility and the load, with the exception of the transmission facilities between the two, will be effectively the same as if they were located at the same substation.

²¹⁹ See, e.g., AEU November 21 ANOPR Comments at 13 ("To the extent that a new large load and new generation or storage resource are geographically and electrically proximate, studying them together would reduce network upgrades, lower costs, and reduce the need for critical supply chain components."); DTE November 21 ANOPR Comments at 10 (integrating the study of load and its supporting generation "reduces the need for network upgrades, optimizes the use of existing infrastructure, and accelerates the timeline for bringing both load and generation online"); Eolian November 21 ANOPR Comments at 18 ("It is obvious from basic engineering principles that generation located near load requires less transmission infrastructure to serve that load than generation located distant from load."); GridStor November 21 ANOPR Comments at 5 ("Siting a large load near or at the same point of interconnection as a new generating facility could reduce the network upgrades needed to interconnect only the load or only the generating facility.").

²²⁰ See AEP December 5 ANOPR Comments at 1; Base Power November 21 ANOPR Comments at 7; CEBA November 21 ANOPR Comments at 8; DCC November 21 ANOPR Comments at 6 (asserting that a clear framework to study large loads paired with generation would resolve development bottlenecks); Eolian November 21 ANOPR Comments at 18-19; Eolian May 19 ANOPR Comments at 2;

96. As commenters in the ANOPR proceeding have recognized, the status quo may result in inefficient and unnecessary development of infrastructure, which leads to unnecessarily higher Network Upgrade costs that may result in unjust and unreasonable rates.²²¹ The Commission has already determined in the PJM Co-Location Order that without the new transmission services that reflect the operational dynamics of co-location arrangements, there could be unnecessary, costly, and inefficient Network Upgrades, increasing Network Upgrade costs.²²² The same result may occur in the absence of new generator interconnection study procedures and generator interconnection services tailored to a new generating facility coming online for the express purpose of serving an electrically proximate large load or large co-located load.²²³

97. SPP recognized this problem and submitted an FPA section 205 filing to implement a new, interim, generator interconnection service and related generator interconnection process, HILLGA, to facilitate the prompt interconnection of generating facilities that are specifically identified for and limited to serving a HILL, which the Commission accepted.²²⁴ The Commission found that HILLGA “reasonably provides a flexible, expedited, and separate serial interconnection process that will facilitate the prompt interconnection of generating facilities that are limited to serving a HILL in the

Google November 21 ANOPR Comments at 7 (calling for nationwide rules enabling proximate load-generation interconnection to “accelerate the pace at which new generation comes online”); Longroad November 21 ANOPR Comments at 8.

²²¹ See, e.g., AEU November 21 ANOPR Comments at 13, AEP December 5 ANOPR Comments at 1-2; Longroad November 21 ANOPR Comments at 8; OPSI November 21 ANOPR Comments at 11.

²²² PJM Co-Location Order, 193 FERC ¶ 61,217 at P 177 (“[F]or Eligible Customers taking service on behalf of Co-Located Loads that do not reserve transmission . . . requiring such Eligible Customers to take NITS on behalf of these Co-Located Loads may in some circumstances result in costly and inefficient transmission system buildout that may not be necessary if such Eligible Customers are willing and able to take a transmission service that requires fewer Network Upgrades to provide, and therefore may result in lower Network Upgrade costs, than would NITS.”).

²²³ See AEP December 5 ANOPR Comments at 1-2 (stating that current processes produce insufficient/inefficient infrastructure and “potentially unsustainable price increases”); Eolian May 19 ANOPR Comments at 2, 10 (contending that a lack of coordinated study leads to unjust and unreasonable outcomes).

²²⁴ SPP HILL Order, 194 FERC ¶ 61,031.

same local area.”²²⁵ We do not expect or propose that PJM adopt an identical process to SPP’s HILLGA process, nor do we preliminarily find that the absence of Tariff provisions specifically mirroring SPP’s Tariff renders PJM’s Tariff unjust and unreasonable. Nevertheless, we remain concerned that the Tariff may be unjust and unreasonable without *any* uniquely tailored interconnection study process and/or generator interconnection service to recognize the reduced transmission system impacts that may result from the interconnection of a generating facility where the interconnection customer has committed, in an interconnection agreement, to limit the generating facility’s output to match the hourly forecast of an electrically proximate large load or large co-located load.²²⁶ To the extent that the interconnection customer’s generating facility is serving an electrically proximate large load, we believe that the generator interconnection service should be of an interim nature until the interconnection customer obtains Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS). To the extent that the interconnection customer’s generating facility is serving a large co-located load, it may be reasonable for the generator interconnection service to be permanent because there will be no injections onto the transmission system and therefore it does not present operational or planning risks for reliability.

98. Another potentially reasonable approach to address our concerns could be to develop a generator interconnection study process that would allow the use of existing ERIS or NRIS of an existing generator to connect a new generating facility and a new large load behind the same point of interconnection of the existing generator with necessary control technologies and/or protection systems, which may include a special protection scheme, that ensure that the net injection does not exceed the amount in the existing generator interconnection agreement.²²⁷ Such an approach could expedite the interconnection study process for a generator planning to serve an electrically proximate

²²⁵ *Id.* P 64.

²²⁶ While, as discussed above, we view such a process that permits generation to serve electrically proximate loads no more than two substations away from the generators to be reasonable, we understand the unique features of PJM’s transmission system may warrant consideration of a more limited definition of electrically proximate. *See* Duke November 21 ANOPR Comments at 21-22; DTE November 21 ANOPR Comments at 8-11 (asserting that studying large loads with electrically proximate generation streamlines interconnection and reduces upgrades); AEU November 21 ANOPR Comments at 13-15.

²²⁷ *See* Constellation June 5 ANOPR Comments at 1-2, 10-13.

(in this case at the same point of interconnection) large load.²²⁸ An additional potentially reasonable approach could be a new load-limited generator interconnection service that allows a new generating facility and new large co-located load seeking to interconnect behind the *same* new point of interconnection, with necessary control technologies and/or protection systems, which may include a special protection scheme, to ensure that there is no injection to the transmission system.²²⁹ It may be reasonable for such a load-limited generator interconnection service to be or not to be of an interim nature. We invite PJM and/or Transmission Owners, in responding to this order or in an FPA section 205 filing, to submit original proposals designed to address the concerns expressed herein and tailored to their unique circumstances.

99. We are concerned that the absence of generator interconnection study procedures and generator interconnection services facilitating the interconnection of a new generating facility that is being brought onto the transmission system in order to serve an electrically proximate large load or large co-located load will result in PJM's current generator interconnection process failing to keep pace with the new large loads seeking to be integrated onto PJM's transmission system.²³⁰ We preliminarily find that this outcome may be unjust and unreasonable because reliance on PJM's current generator interconnection processes for generating facilities serving electrically proximate large loads or large co-located loads could result in unnecessary interconnection delays, unnecessary Network Upgrades, and an otherwise inefficient expansion of the transmission system, imposing unnecessary delays and costs on transmission customers.

100. PJM should explain whether the Tariff remains just and reasonable without, for example, provisions that establish: (1) a new generator interconnection study process and new interim generator interconnection service that reflect an interconnection customer's

²²⁸ See *id.* at 5 (explaining that when new generation load pairings "are sited at an existing generator's Point of Interconnection and fall within the same study parameters reflected by that existing generator's interconnection, they benefit from studies and upgrades already completed for that existing generator and can come on more rapidly without jeopardizing reliability").

²²⁹ See MISO November 21 ANOPR Comments at 13; *see also* MISO TOs April 3 ANOPR Comments at 13-14.

²³⁰ See Helion November 21 ANOPR Comments at 1 (noting interconnection delays are the biggest barrier to adding new generation); Oracle November 21 ANOPR Comments at 1 (noting significant delays in access to sufficient energy for data centers); OPSI November 21 ANOPR Comments at 11 (explaining that expedited study encourages loads to bring their own generation); Enchanted Rock November 21 ANOPR Comments at 4; Microsoft November 21 ANOPR Comments at 8-9.

commitment, in a generator interconnection agreement, to limit a generating facility's output to match the hourly forecast of an electrically proximate large load or large co-located load; or (2) a generator interconnection study process that allows the use of the existing ERIS or NRIS of an existing generator to connect a new generating facility and a new large load behind the same point of interconnection of the existing generator with necessary control technologies and/or protection systems, which may include a special protection scheme, that ensures that the net injection does not exceed the amount in the existing generator interconnection agreement; or (3) a new generator interconnection service that allows a new generating facility and new large co-located load seeking to interconnect behind the same new point of interconnection with necessary control technologies and/or protection systems, which may include a special protection scheme, to ensure that there is no injection to the transmission system. We note that, with respect to numbers (2) or (3), these approaches could be either interim or permanent. These approaches may not be mutually exclusive.

101. Given that generator interconnection service in and of itself does not convey transmission service, we encourage PJM to consider, in responding to these concerns, what type of transmission service an Eligible Customer will need to take on behalf of the electrically proximate large load or large co-located load.²³¹ We note that, in the PJM Co-Location Order, the Commission found that the Eligible Customer must take transmission service on behalf of co-located load that will not withdraw energy from the transmission system, even if it is 0 MW.²³²

E. Informational Report

102. The rapid addition and proliferation of large loads without commensurate additions of supply or demand-side resources presents resource adequacy concerns. As discussed above and highlighted in the ANOPR, the growth of demand, and the speed of such growth, is driven in large part by the interconnection of large loads. While not expressly contemplated in the ANOPR, commenters highlight the strain rapid demand growth is putting on resource adequacy in many regions.²³³ Indeed, the relative speed and concentration at which large loads are seeking to interconnect appears to be outpacing the addition of new generation, which in turn heightens reliability risks and

²³¹ See SPP HILL Order, 194 FERC ¶ 61,031 at P 34.

²³² PJM Co-Location Order, 193 FERC ¶ 61,217 at P 206.

²³³ See, e.g., Entergy November 21 ANOPR Comments at 29-30; Eolian November 21 ANOPR Comments at 16-17; Industrial Customers November 21 ANOPR Comments at 24-26; R Street November 21 ANOPR Comments at 1; South Dakota Commission November 13 ANOPR Comments at 5; Talen December 5 ANOPR Comments at 7.

drives up costs to ratepayers.²³⁴ We are concerned that PJM and load serving entities are unable to plan adequate generation to serve all load at the pace such load seeks to connect.

103. We recognize that RTOs/ISOs are engaging in efforts to more rapidly interconnect generation that is needed to serve this unprecedented growth in load. In particular, PJM's Reliability Resource Initiative and Expedited Interconnection Track have provided pathways for expedited interconnection for generation.²³⁵ Further, as detailed above and in informational reports submitted by PJM,²³⁶ PJM has ongoing stakeholder processes to address resource adequacy issues related to large load additions, including a voluntary "Bring Your Own New Generation" pathway for large loads, a "connect-and-manage" framework applicable to new large loads that do not bring commensurate new generating capacity, and a reliability backstop procurement.²³⁷ While we are encouraged by the implementation of such processes to ensure resource adequacy and faster interconnection and ongoing stakeholder discussions, we remain concerned that these efforts may fall short in light of generator retirements and tightening supply conditions.

104. Accordingly, we direct PJM to submit in Docket No. EL26-67-000, within 30 days of the date of issuance of this order, a detailed informational report on the current status of proposals under consideration in its stakeholder process to address the issue of resource adequacy to serve new large loads. We also strongly encourage new proposals to the extent necessary to address these concerns. The informational report must include a detailed schedule of key milestones, such as stakeholder or PJM Board votes, that includes the estimated date on which PJM expects to file any such proposals with the Commission. Additionally, as part of this informational report, we direct PJM to identify any problem statements, issue charges, or other ongoing stakeholder processes that aim to increase the pace of adding generating capacity in the PJM region. The informational

²³⁴ See, e.g., Eolian November 21 ANOPR Comments at 16-17; David Gardiner & Associates November 21 ANOPR Comments at 1-2; Joint Consumer Advocates December 5 ANOPR Comments at 2; PSEG November 21 ANOPR Comments at 8; Southern California Edison December 5 ANOPR Comments at 3.

²³⁵ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084; *order on reh'g*, 192 FERC ¶ 61,085 (2025); PJM EIT Order, 195 FERC ¶ 61,197.

²³⁶ PJM Interconnection, L.L.C., Informational Report, Docket No. EL25-49-000, et al. (filed Jan. 20, 2026); PJM Interconnection, L.L.C., Supplemental Informational Report, Docket No. EL25-49-000, et al. (filed Feb. 23, 2026); PJM Interconnection, L.L.C., Second Supplemental Informational Report, Docket No. EL25-49-000, et al. (filed Mar. 9, 2026).

²³⁷ See *supra* P 33.

report must include a detailed schedule of such initiatives, including timing of the stakeholder process and dates of any anticipated filings with the Commission.

IV. Briefing Questions

105. We note that large loads, including data centers, are actively working with transmission owners and other relevant entities to interconnect to, and to take interconnection and/or transmission service from, the transmission system and may be at varying stages of that process. We appreciate that different large loads are currently at different stages of that process. We also understand that large loads and Eligible Customers taking transmission service on behalf of large loads are negotiating, entering into, and/or have executed various agreements related to interconnecting to the transmission system and/or the provision of transmission service. We direct further briefing regarding how PJM and the Transmission Owners, in responding to the order to show cause, should protect existing commercial arrangements including: (1) what would be a reasonable implementation period to ensure minimal disruption to such existing commercial arrangements, and (2) how to allow a reasonable amount of time to finalize ongoing agreements that are nearing completion as of the date such Tariff provisions are filed with the Commission.

106. Today's order proposes, as part of a potential replacement rate, to establish new transmission services that recognize flexible large loads' ability and willingness to limit their use of the transmission system under certain conditions. As we assess this proposal, we also consider how these new transmission services might affect other parts of PJM's Tariff and/or processes. Specifically, what, if any, potential impacts on regional and local transmission planning would arise from the introduction of the new transmission services discussed herein? For example, when planning for load growth, how would transmission providers and planners account for flexible large loads' potential preference to take the new transmission services, including potential uncertainties around the type, location, and quantity of such expected loads?

107. Today's order preliminarily finds that PJM's Tariff appears to be unjust and unreasonable without the inclusion of cost shifting protections. We find that there may be a variety of possible approaches to protect customers from significant cost shifts associated with Network Upgrades triggered by large loads. To that end, we direct respondents to include information regarding potential structures for agreements between the transmission owner/provider and an Eligible Customer to prevent unjust and unreasonable cost shifts among transmission customers related to Network Upgrade costs required for large loads. Further, please include information on what an appropriate minimum level of cost recovery and financial security from an Eligible Customer would be under any such agreements.

108. Today's order preliminarily finds that PJM's Tariff appears to be unjust and unreasonable because it lacks clear and consistent provisions requiring the evaluation of alternative transmission technologies. The order directs PJM to explain whether the Tariff remains just and reasonable without provisions that: (1) require the evaluation of alternative transmission technologies in transmission service request studies, using models that are capable of evaluating the transmission system to accurately account for advanced transmission technologies, in all instances, without the need for a request from the Eligible Customer seeking transmission service on behalf of large load; and (2) if traditional Network Upgrades are selected instead of alternative transmission technologies, inclusion in the study report to the Eligible Customer seeking transmission service on behalf of large load of a sufficiently clear demonstration of why alternative transmission technologies are not feasible (i.e., would not resolve reliability violations identified or meet the relevant planning criteria) or would not result in lower costs or a faster timeline for accommodating the transmission service request. As noted above, to the extent stakeholders believe that specific characteristics of providing transmission service to Eligible Customers on behalf of large loads warrant requirements beyond those contemplated here, we seek further briefing.

109. Today's order preliminarily finds that PJM's Tariff appears to be unjust and unreasonable because it does not contain provisions allowing an interconnection customer serving electrically proximate large load or large co-located load to seek generator interconnection service(s) that reflects the operational dynamics of serving such loads. Any filings or tariff changes submitted in response to this order should address the following questions:

- a. To what extent would PJM allow an interconnection customer's generating facility serving electrically proximate large load or large co-located load to participate in PJM's energy and ancillary services market, and if PJM were to allow them to participate, what restrictions or mitigation would PJM apply?
- b. To the extent that PJM plans for the electrically proximate large load or large co-located load associated with an interconnection customer's generating facility for resource adequacy purposes, would PJM account for the generating facilities serving electrically proximate large load or large co-located load in the resource adequacy construct? If applicable, would PJM allow the generating facilities serving electrically proximate large load or large co-located load to participate in PJM's capacity market? If so, would PJM accredit these generating facilities using the same method as other PJM generating facilities?

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the FPA, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the FPA (18 C.F.R. Chapter I), the Commission hereby institutes a proceeding in Docket No. EL26-67-000 as discussed in the body of this order.

(B) PJM and the Transmission Owners are hereby directed, within 60 days of the date of the order, either: (1) to show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) to explain what changes to the Tariff they believe would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential and, therefore, proceeds to establish a replacement Tariff.

(C) PJM is directed to submit an informational report within 30 days of the date of issuance of this order, as discussed in the body of this order.

(D) Any interested person desiring to be heard in Docket No. EL26-67-000 must file a notice of intervention or motion to intervene, as appropriate, with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, in accordance with Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2025), within 21 days of the date of issuance of this order. The Commission encourages electronic submission of interventions in lieu of paper using the "eFiling" link at <http://www.ferc.gov>. Persons unable to file electronically may file by U.S. mail addressed to Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, DC 20426, or by hand (including courier) delivery to Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

(E) Interested entities may respond within 30 days of PJM's and the Transmission Owners' filing, addressing either or both of: (1) whether the Tariff remains just and reasonable and not unduly discriminatory or preferential; and (2) if not, what changes to the Tariff should be implemented as a replacement rate.

(F) The Secretary shall promptly publish in the Federal Register a notice of the Commission's initiation of the proceeding under section 206 of the FPA in Docket No. EL26-67-000.

(G) The refund effective date in Docket No. EL26-67-000 pursuant to section 206 of the FPA shall be the date of publication in the Federal Register of the notice discussed in Ordering Paragraph (F) above.

By the Commission. Chairman Swett is concurring with a separate statement attached.
Commissioner Rosner is concurring with a separate statement

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attached.

Commissioner See is concurring with a separate statement attached.

Commissioner Chang is concurring with a separate statement attached.

Commissioner LaCerte is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Secretary.

Appendix - Commenters in Docket No. RM26-4-000

Advanced Energy Management Alliance (AEMA)
Advanced Energy United (AEU)
Advancing Modern Powerlines Coalition (together with Working for Advanced Transmission Technologies Coalition, WATT and Advancing Modern Powerlines)
Advocates for Consumer Regulated Electricity
AES Corporation (AES)
AI Supply Chain Alliance
Alexandre Figueras, on behalf of Monza Tech
Alliance for Tribal Clean Energy
Alliant Energy Corporate Services, Inc.
Amazon Energy LLC (Amazon)
America's Power
American Chemistry Council
American Clean Power Association
American Conservation Coalition
American Council on Renewable Energy (ACORE)
American Electric Power Service Corporation²³⁸
American Public Gas Association
American Public Power Association (APPA)
American Terawatt, Inc. (American Terawatt)
American Transmission Company LLC²³⁹
Americans for a Clean Energy Grid
Antora Energy, Inc.
Arevia Power
Arizona Public Service Company
Arkansas Public Service Commission
Attorney General of the State of Oklahoma

²³⁸ American Electric Power Service Corporation submitted comments on behalf of its affiliates Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, Public Service Company of Oklahoma, Southwestern Electric Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Inc., AEP Oklahoma Transmission Company, Inc., and AEP Southwestern Transmission Company, Inc.

²³⁹ American Transmission Company LLC submitted comments on behalf of itself and its corporate manager ATC Management Inc.

Base Power Company, Inc (Base Power).
Bloom Energy Corporation
Buckeye Power, Inc. (Buckeye)
Calibrant Energy Holdings, LLC (Calibrant)
California Department of Water Resources State Water Project (California DWR)
California Independent System Operator Corporation
California Public Utilities Commission (CPUC)
Center for Biological Diversity
Chevron U.S.A., Inc.
Clean Energy Buyers Association (CEBA)
ClearPath, Inc. (ClearPath)
Confederated Tribes and Bands of the Yakama Nation
Constellation Energy Generation, LLC (Constellation)
Consumer Energy Alliance
Consumers Energy Company
Critical Loop, Inc. (Critical Loop)
Crusoe Energy Systems, Inc. (Crusoe)
CTC Global Corporation
Data Center Coalition (DCC)
David Gardiner & Associates
Delaware Division of the Public Advocate (together with Pennsylvania Office of
Consumer Advocate, Joint Consumer Advocates)²⁴⁰
Digital Energy Council
Digital Power Network
Distributed Capacity Parties²⁴¹
Dr. Elisa Nelson
DTE Electric Company (DTE)
Duke Energy Corporation (Duke)
EDF Power Solutions, Inc. (EDF Power)
Edison Electric Institute (EEI)
Electricity Consumers Resource Council (ELCON)
Electricity Customers Alliance (ECA)
Electric Power Supply Association (EPSA)
Emerald AI (Emerald)
Enchanted Rock, LLC
Energy New England, LLC

²⁴⁰ The Illinois Attorney General joined the Joint Consumer Advocates in filing reply comments.

²⁴¹ Distributed Capacity Parties include: Cloverleaf Infrastructure; Spark Community Investment d/b/a Sparkfund; and Voltus, Inc.

Energy Trading Institute
ENGIE North America, Inc. (ENGIE)
Entergy Services, LLC (Entergy)²⁴²
Environmental Law & Policy Center
Eolian L.P. (Eolian)
Equinix, Inc.
esVolta, LP
ETX Upstream, LLC
Eversource Energy²⁴³
Exelon Corporation (Exelon)²⁴⁴
Fervo Energy Company (Fervo)
FirstEnergy Service Company²⁴⁵
Fluence
Front Door Technologies LLC
FuelCell Energy, Inc.
Georgia Public Service Commission
Geronimo Power, LLC (Geronimo)
Google LLC (Google)
Governors Josh Shapiro and Glenn Youngkin
GridCARE
GridStor LLC (GridStor)
Harvard Electricity Law Initiative

²⁴² Entergy submitted comments on behalf of the Entergy Operating Companies, which include Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.

²⁴³ Eversource Energy submitted comments on behalf of its affiliates The Connecticut Light and Power Company, NSTAR Electric Company, and Public Service Company of New Hampshire, and through its agent Eversource Energy Service Company.

²⁴⁴ Exelon submitted comments on behalf of itself and its affiliates Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Inc., Delmarva Power and Light Company, PECO Energy Company, and Potomac Electric Power Company.

²⁴⁵ FirstEnergy Service Company submitted comments on behalf of itself and its affiliates American Transmission Systems, Inc., Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, Keystone Appalachian Transmission Company, The Potomac Edison Company, Monongahela Power Company, and Trans-Allegheny Interstate Line Company.

Helion Energy (Helion)
Herbert Schrayschuen
Heron Power Electronics Company
Indiana Energy Association
Indicated PJM Transmission Owners (PJM TOs)²⁴⁶
Industrial Customer Organizations (Industrial Customers)²⁴⁷
Information Technology Industry Council
Infrastructure Masons, Inc. (Infrastructure Masons)
Institute for Progress
International Energy Credit Association
Invenergy²⁴⁸
Iron Mountain Data Centers, LLC

²⁴⁶ PJM TOs include: AEP on behalf of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc.; AMP Transmission, LLC; City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power; City of Hamilton, OH; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation, on behalf of Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Inc., Delmarva Power & Light Company, PECO Energy Company, and Potomac Electric Power Company; FirstEnergy Service Company, as agent for its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, Keystone Appalachian Transmission Company, The Potomac Edison Company, Monongahela Power Company and Trans-Allegheny Interstate Line Company; Old Dominion Electric Cooperative; PPL Electric Utilities Corporation; Rockland Electric Company; Southern Maryland Electric Cooperative, Inc.; UGI Utilities Inc; and Wabash Valley Power Association, Inc.

²⁴⁷ Industrial Customers include: the Industrial Energy Consumers of America, the American Forest & Paper Association, the PJM Industrial Customer Coalition, and the Coalition of MISO Transmission Customers

²⁴⁸ Invenergy includes: Invenergy Wind Development North America LLC, Invenergy Solar Development North America LLC, and Invenergy Thermal Development Holdings LLC.

ISO New England, Inc.
ITC Holdings Corp. (ITC)
Jason Miller, on behalf of VEIR Inc.
Kansas Corporation Commission (Kansas Commission)
L. Lynne Kiesling
L.M. Marlowe
Land Trust Alliance
Large Public Power Council
Lauren Hopkins
LEAN Energy US
Load Flexibility Parties²⁴⁹
Long Island Power Authority
Longroad Energy Holdings, LLC (Longroad)
Louisiana Public Service Commission
LS Power Development, LLC (LS Power)
Maine Office of the Public Advocate
Maryland Energy Administration
Maryland Public Service Commission (Maryland Commission)
Maven Solutions
MCC Economics and Finance
Meta Platforms, Inc.
Michigan Attorney General Dana Nessel
Microsoft, Inc. (Microsoft)
Midcontinent Independent System Operator, Inc.
MISO Transmission Owners (MISO TOs)²⁵⁰

²⁴⁹ Load Flexibility Parties include: Enerwise Global Technologies, LLC d/b/a CPower, Enel North America, Inc., and Voltus, Inc.

²⁵⁰ MISO TOs include: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; Citizens Electric Corporation; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; Entergy Texas, Inc.; Great River Energy; GridLiance Heartland LLC; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company d/b/a AES Indiana; Lafayette Utilities System; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin

Mississippi Public Service Commission
Missouri Public Service Commission (Missouri Commission)
Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM (PJM IMM)
Nathan Peterson
National Association of Regulatory Utility Commissioners
National Association of State Utility Consumer Advocates
National Conference of State Legislatures (NCSL)
National Congress of American Indians
National Grid PLC (National Grid)²⁵¹
National Rural Electric Cooperative Association (NRECA)
Nebraska Power Review Board (Nebraska Board)
New England States Committee on Electricity
New England Conference of Public Utility Commissioners
New England Consumer-Owned Systems²⁵²

corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Republic Transmission, LLC; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a CenterPoint Energy Indiana South); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc

²⁵¹ National Grid submitted comments behalf of its affiliates: Niagara Mohawk Power Corporation; New England Power Company; New England Electric Transmission Corporation; New England Hydro-Transmission Corporation; New England Hydro-Transmission Electric Company, Inc.; and Massachusetts Electric Company.

²⁵² New England Consumer-Owned Systems include: Belmont Municipal Light Department, Block Island Utility District, Braintree Electric Light Department, Concord Municipal Light Plant, Danvers Electric Division, Georgetown Municipal Light Department, Groveland Electric Light Department, Hingham Municipal Lighting Plant, Hudson Light & Power Department, Littleton Electric Light & Water Department, Merrimac Municipal Light Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, North Attleborough Electric Department, Norwood Municipal Light Department, Clear River Electric & Water District, Rowley Municipal Lighting Plant, Stowe Electric Department, Taunton Municipal Lighting Plant, Town of Wallingford, Connecticut Department of Public Utilities Electric Division, Westfield Gas and Electric Light Department, and Mid-Coast Regional Redevelopment Authority.

New England Public Systems²⁵³
New Mexico Public Regulation Commission (New Mexico Commission)
New York Independent System Operator, Inc.
New York State Department of State Utility Intervention Unit (NY UIU)
New York Public Service Commission
New York State Reliability Council
New York Transmission Owners²⁵⁴
North American Electric Reliability Corporation
North Carolina Utilities Commission
North Carolina Utilities Commission Public Staff
North Dakota Public Service Commission
Northeastern Rural Electric Membership Corporation
NRG Energy, Inc.
Office of the Illinois Attorney General (Illinois AG)
Office of the Ohio Consumers' Counsel (OCC)
Oklahoma Corporation Commission
Oklo Inc. (Oklo)
Old Dominion Electric Cooperative (ODEC)
Oncor Electric Delivery Company LLC
ON Energy Storage, Inc.
OpenAI Inc.
Oracle America, Inc. (Oracle)
Organization of MISO States, Inc. (OMS)
Organization of PJM States, Inc. (OPSI)
Paces AI Inc.
Pacific Gas & Electric Company
Paige Lambermont, on behalf of Competitive Enterprise Institute
Paul Statchen
Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission (Pennsylvania Commission)
Pew Charitable Trusts Energy Modernization Project
PJM Interconnection, LLC (PJM)

²⁵³ New England Public Systems include: Connecticut Municipal Electric Cooperative, Massachusetts Municipal Wholesale Electric Company, and Vermont Public Power Supply Authority.

²⁵⁴ New York Transmission Owners include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corp. (d/b/a National Grid), Orange and Rockland Utilities, Inc., Long Island Power Authority, and Rochester Gas and Electric Corporation.

Power for Tomorrow
PPL Corporation²⁵⁵
Prime Mover Institute
PSEG Companies (PSEG)²⁵⁶
Public Citizen, Inc.
Public Interest Organizations (PIOs)²⁵⁷
Public Utilities Commission of Ohio's Office of the Federal Energy Advocate (Ohio FEA)
R Street Institute (R Street)
Rewiring America
MCC Economics Ltd.
RWE Clean Energy, LLC
Sarah McKinley
Shell Energy North America (US), L.P.
Sierra Club
SMA Solar Technology AG
Solar Energy Industries Association
South Carolina Office of Regulatory Staff
South Dakota Public Utilities Commission (South Dakota Commission)
Southeast Public Interest Organizations (Southeast PIOs)²⁵⁸
Southern California Edison Company (Southern California Edison)
Southern Companies²⁵⁹

²⁵⁵ PPL Corporation submitted comments on behalf of the PPL Companies, which include PPL Electric Utilities Corporation, Louisville Gas & Electric Company and Kentucky Utilities, and The Narragansett Electric Company d/b/a Rhode Island Energy.

²⁵⁶ PSEG Companies include: Public Service and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC, which are each wholly-owned, direct or indirect subsidiaries of Public Service Enterprise Group Incorporated.

²⁵⁷ PIOs include: Clean Air Task Force, Inc., Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania, Earthjustice, Environmental Defense Fund, Montana Environmental Information Center, Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, and Southern Environmental Law Center.

²⁵⁸ Southeast PIOs include: Southern Environmental Law Center, Appalachian Voices, North Carolina Sustainable Energy Association, South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy.

²⁵⁹ Southern Companies include: Georgia Power Company, Alabama Power Company, and Mississippi Power Company.

Southern Maryland Electric Cooperative, Inc.
Southwest Power Pool, Inc.
Southwest Power Pool Transmission Owner Group²⁶⁰
Splight Inc. (Splight)
State Entities²⁶¹
Steel Manufacturers Association
Switch, Ltd. (Switch)
Talen Energy Corporation (Talen)
Terraflux LLC (Terraflux)
Tesla, Inc.
Texas Blockchain Council
Thermal Battery Alliance
Tract Holding Company I, LLC (Tract)
Transmission Access Policy Study Group (TAPS)
Tri-State Generation and Transmission Association, Inc. (Tri-State)
Travis Fisher, on behalf of Cato Institute
U.S. Chamber of Commerce (Chamber of Commerce)
U.S. Energy Storage Coalition
U.S. House of Representatives Committee on Energy and Commerce Ranking Members²⁶²
U.S. Representatives²⁶³
U.S. Senate Committee on Energy and Natural Resources

²⁶⁰ Southwest Power Pool Transmission Owner Group includes: American Electric Power Service Corporation, Evergy Kansas Central, Inc., Evergy Metro, Inc., Evergy Missouri West, Inc., Oklahoma Gas and Electric Company, and Xcel Energy Services Inc., on behalf of Southwestern Public Service Company.

²⁶¹ State Entities include: Massachusetts Attorney General's Office, the Arizona Attorney General's Office, the Colorado Attorney General's Office, the Connecticut Office of Consumer Counsel, the Maryland Office of People's Counsel, the Minnesota Attorney General's Office, the Office of the Nevada Attorney General, Bureau of Consumer Protection, the New Hampshire Office of the Consumer Advocate, the Oregon Attorney General, and the Rhode Island Division of Public Utilities and Carriers.

²⁶² Submitted by Frank Pallone, Jr. (Ranking Member) and Kathy Castor (Ranking Member, Subcommittee on Energy).

²⁶³ The U.S. Representatives that submitted comments include: Suhas Subramanyam, John W. Mannion, Mike Quigley, and Donald S. Beyer Jr.

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U.S. Senators²⁶⁴

U.S. Senator Jon Ossoff

Union of Concerned Scientists (UCS)

Vantage Data Centers (Vantage)

Verrus

Virginia State Corporation Commission (Virginia Commission)

Vistra Corp. (Vistra)

Washington Utilities and Transportation Commission

WIRES

Wisconsin Electric Company

Wisconsin Public Service Corporation

²⁶⁴ The U.S. Senators that submitted comments include: Edward J. Markey, Chris Van Hollen, Elizabeth Warren, Peter Welch, Raphael Warnock, Richard Blumenthal, and Adam B. Schiff.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

Docket No. EL26-67-000

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company
PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company

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Silver Run Electric, LLC
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

(Issued June 18, 2026)

SWETT, Chairman, *concurring*:

1. Today, we take historic action to push our country's electric markets and economy into the future—a future of fair cost allocation, unprecedented transparency for the American ratepayer, respect for states' rights, efficient markets and speed to power. Last October, Secretary Wright articulated the monumental, generational and “urgent” challenge FERC must solve for our country when he directed us to develop “reforms to ensure the timely and orderly interconnection of large loads to the transmission system.”¹ I strongly agree. And now, through this suite of six orders, we deliver.

2. Simply put, the show cause orders the Commission issues today to each of the six electric markets subject to its jurisdiction find that the status quo across much of the country is not good enough.² Nowhere close. The record prompted by the Secretary's ANOPR leaves no doubt that most of the markets (and their existing rules) are inherently slow and prohibitive of the dexterity necessary to adapt to and power societal evolution—whether brought about by technological innovation or sustaining the great industrial economy that anchors America.

3. I wholeheartedly, fully concur with these orders, which we carefully crafted to execute upon the problems the Secretary identified in a manner that is quick, efficient,

¹ Advance notice of proposed rulemaking (ANOPR) *Interconnection of Large Loads to the Interstate Transmission System*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025) (ANOPR); see Letter from Chris Wright, Sec'y, U.S. Dep't of Energy (Oct. 23, 2025) (Secretary's Letter).

² *Cal. Indep. Sys. Operator Corp.*, 195 FERC ¶ 61,214 (2026) (CAISO); *ISO New Eng. Inc.*, 195 FERC ¶ 61,215 (2026) (ISO-NE); *Midcontinent Indep. Sys. Operator, Inc.*, 195 FERC ¶ 61,212 (2026) (MISO); *N.Y. Indep. Sys. Operator, Inc.*, 195 FERC ¶ 61,216 (2026) (NYISO); *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211 (2026) (PJM); *Sw. Power Pool, Inc.*, 195 FERC ¶ 61,213 (2026) (SPP) (collectively, Orders to Show Cause).

and legally durable. I write separately to highlight certain considerations underlying the Commission's procedural approach to delivering on the ANOPR and to today's orders.

4. Based on my analysis of the extensive record and numerous ongoing substantive stakeholder interactions, I have determined that the most productive way to “build upon the[] principles”³ in the ANOPR and “work expeditiously”⁴ towards a solution is to issue individualized orders to show cause to each market.⁵ That is so for two main reasons.

5. First, the record the Commission collected in response to the challenges identified in the ANOPR and subsequent resulting developments indicate that an approach that honors the ANOPR principles but accounts for widening regional variation may now be more efficient than a one-size-fits-all rule.⁶ The world has changed a great deal since last October. The ANOPR itself, including the articulated principles, appears to have shifted the playing field and prompted great progress across several electric markets. This change (and the Commission's alignment with the Secretary) is well illustrated by a number of landmark orders approving several market new constructs that we issued since October, which together operationalize the Secretary's principles and laid groundwork for meaningful reform and today's actions.⁷ While working to develop those orders, the

³ Secretary's Letter at 2.

⁴ *Id.*

⁵ See *SEC v. Chenery Corp.*, 332 U.S. 194, 202-03 (1947) (“[A]n administrative agency must be equipped to act either by general rule or individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity. . . . [T]he choice made between proceeding by general rule or by individual, *ad hoc* litigation is one that lies primarily in the informed discretion of the administrative agency.”); *Wis. Gas Co. v. FERC*, 770 F.2d 1144, 1166 (D.C. Cir. 1985) (“It is a well-settled principle of administrative law that the decision whether to proceed by rulemaking or adjudication lies within the broad discretion of the agency.”).

⁶ “[T]he Commission may rely on ‘generic’ or ‘general’ findings of a systemic problem to support imposition of an industry-wide solution.” *Interstate Nat. Gas Ass’n of Am. v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002) (internal citations omitted). However, the Commission “has long allowed different regional transmission organizations to follow different rules, in recognition of regional variations including potential differences in ‘geographic size and location.’” *Cent. Hudson Gas & Elec. Corp. v. FERC*, 138 F.4th 531, 539 (D.C. Cir. 2025) (internal citations omitted).

⁷ See *id.* P 2 & nn.6-11.

Commission has simultaneously devoted significant attention to evaluating the various procedural paths through which we might comprehensively deliver.

6. Individual show cause proceedings will allow the Commission to ensure that solutions to the problems the Secretary identified are tailored to the specific, varied circumstances and market constructs of each region. Indeed, a careful review of today's six orders reveals the many ways in which those orders are customized for each market's unique circumstances and progress (or lack thereof) towards serving large load. To name just a few examples, the orders recognize ongoing stakeholder processes in various regions and are adapted to existing tariff provisions concerning large and co-located loads; account for regional variances in allocating rights and responsibilities among RTOs/ISOs and the transmission owners; leave room for each market to tailor operational requirements for large loads that are particular to their region; and otherwise account for incumbent regional differences on topics such as cost allocation and cost transparency, study processes, and network upgrade procedures.

7. Proceeding via show cause proceedings will also allow the markets (and their respective transmission owners) to explain, in the first instance, how to address the Commission's concerns. These entities have the deepest understanding of their respective regions and are best positioned to implement solutions we identified, in the most expeditious manner. The Commission will promptly evaluate their responses to today's orders, and, with input from stakeholders, swiftly establish appropriate reforms.

8. Second, proceeding via individual show cause orders will allow the Commission to act more quickly than through traditional rulemaking. Notice-and-comment rulemaking may not capitalize upon individual market progress prompted since October and would be unduly time-consuming,⁸ as it also inevitably would require the additional steps of accommodating the regional variations of the approach we take today. Rulemaking efforts can be particularly inefficient when, as here, they risk incubating uncertainty after progress has begun, and diverting scarce stakeholder resources away from other endeavors, such as the development of market-specific reforms submitted to the Commission under section 205 of the Federal Power Act (FPA). (To be clear, we very much encourage 205 submissions encapsulating the principles we articulate in the 206s, and with all due deliberate haste.)

9. Furthermore, rulemaking requires a lengthy series of steps before the proposed reforms would actually take effect—e.g., a NOPR, then a final rule, then potential orders on rehearing, and then a “compliance” process in which affected parties make filings (or, more likely, multiple rounds of filings) explaining how they intend to implement the rule.

⁸ See, e.g., Comments of Talen Energy Corporation, Docket No. RM26-4, at 5-6 (filed Nov. 21, 2025).

By their nature, these procedures take time. For example, the compliance process for the Commission's Order No. 2023⁹ (which matured out of an ANOPR issued in July 2021 and a NOPR issued in June 2022) still is not fully complete as of June 2026. The compliance process for Order No. 2222¹⁰ (NOPR issued in November 2016) could be considered completed in May 2026; however, even with that timing, not all of the RTOs/ISOs have yet fully implemented their Commission-accepted market rules. I provide these examples not to suggest that the completion of a rulemaking process on the interconnection of large loads would take this long,¹¹ but rather to make clear the scope of the years-long delays in implementation that might be expected if the Commission elected to proceed via a NOPR. By contrast, we expect that individual show cause proceedings for each of the RTO/ISOs will enable the Commission to spearhead lasting reform much more expeditiously.

10. The six markets together cover nearly two-thirds of load subject to Commission-jurisdictional rates, and therefore focusing initially on those regions is a prudent first step. But I am under no illusion that the challenges discussed in today's orders are somehow unique to the RTO/ISO regions. Our actions today do not foreclose the possibility of a future rulemaking, and nor do they prevent us from acting on filings made under sections 205 and 206 of the FPA. I encourage transmission providers and other stakeholders outside RTO/ISO regions to make individual filings to address the issues we discuss today.

11. FERC is no longer the sleepy, responsive agency of the past—our country cannot afford for it to be. This is a time for the best thinkers we have to collaborate on solving our biggest problems, and thus it is my great honor to deliver a solution that honors the Secretary's goals.

⁹ *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

¹⁰ *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021).

¹¹ I do not mean to suggest that the public utilities subject to compliance under these rulemakings—or the Commission itself—have been derelict. The time-consuming nature of the compliance process is a natural consequence of complex, nuanced efforts toward tariff reform. As Chairman, I will continue to evaluate Commission directives to ensure that obligations on regulated entities are not unduly burdensome and to make certain that Commission action during the compliance process is as timely as possible.

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For these reasons, I respectfully concur.

Laura V. Swett
Chairman

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

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AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company
PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company

Docket No. EL26-67-000

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Silver Run Electric, LLC
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

(Issued June 18, 2026)

ROSNER, Commissioner, *concurring*:

1. The electric industry is in the midst of changes not seen in a generation. Compared to more traditional load growth, the large loads seeking to connect to the grid today are larger, sometimes by orders of magnitude, and more concentrated. They also exhibit different operational characteristics, such as the ability to quickly change their energy consumption, sometimes in seconds. Often, these large loads seek to connect to the grid as quickly as possible. And because of these dynamics, large loads are rapidly driving the need for new transmission infrastructure and energy supply. This creates new challenges that, if unaddressed, could jeopardize the reliability and affordability of the grid on which we all depend.

2. Today, we are taking an important step toward addressing these challenges. We are opening a dialogue with each of the six RTO/ISOs on a series of reforms that are tailored to address the unique reliability and affordability challenges posed by large load growth and the infrastructure buildout needed to serve dramatically growing demand. Informed by the record developed in response to the Secretary of Energy's October 2025 ANOPR,¹ and by innovative proposals that stakeholders have filed with the Commission under FPA section 205, today's orders are aimed at ensuring that the grid remains reliable and affordable for *all* customers, especially residential customers. It is also crucial that we unlock the immense economic opportunity that once-in-a-generation growth represents. While each order's specific focus varies according to the progress that each RTO/ISO has made, our actions today fit broadly into four key pillars that, taken together, provide a foundation for durable reform. Today, we are: (1) Protecting Consumers, (2) Safeguarding Reliability, (3) Enhancing Transparency, and (4) Fostering Innovation (*see Figure 1*). I write separately to explain how.

¹ U.S. Dep't of Energy, Secretary of Energy Chris Wright, Direction that the Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act (Oct. 23, 2025).

3. **Protecting Consumers:** Today's orders include key protections that promote affordability. First, today's orders require "Cost Recovery Agreements", which are designed to ensure that large loads pay their fair share of the costs incurred to serve them, regardless of whether the large load comes online as planned. Thus, if new infrastructure is built to accommodate a data center, and that data center doesn't show up, residential customers are not left on the hook to pay the costs. Cost Recovery Agreements prevent those costs from being shifted to residential customers. Depending on how they are structured, Cost Recovery Agreements can also address the potentially uneven pacing of new infrastructure costs, where grid upgrade costs may hit customer bills *before* the large load is fully online and energized. Data centers have committed to paying their own way.² Today, with "Cost Recovery Agreements," we are taking steps to ensure that those commitments are honored. I note, however, that the door remains open to other creative, regionally-specific ideas to protect consumers. If there are other ways to accomplish that goal, I welcome those proposals.

4. Another win for consumers is requiring RTO/ISOs to consider grid enhancing technologies (GETs), including dynamic line ratings, when adding new large loads to the grid. GETs are technologies that squeeze more juice out of the existing grid, reducing the need for expensive upgrades and speeding up the time connect. Ensuring that RTO/ISOs consider GETs in the planning process—and if GETs are not used, explain why—not only helps new large loads get connected more quickly, but is also a commonsense step towards saving *all* consumers money. Put differently, today's orders will help us understand if we are leaving efficiencies on the table, an outcome we cannot afford.

5. **Safeguarding Reliability:** Today's orders safeguard reliability. They help ensure that RTO/ISOs use study procedures and operational requirements that reflect large loads' unique characteristics and the reliability impacts of connecting them to the grid. Those novel characteristics and reliability impacts are well-documented, and it is not clear if existing study procedures or operational requirements account for them. Clear, comprehensive, and specifically tailored study procedures and operational requirements are needed, such as enhanced data reporting and telemetry to increase visibility into how these loads interact with the grid, and today's orders represent progress towards this goal.

6. Finally, although not part of today's orders, I want to highlight NERC's ongoing efforts to establish registration criteria for large computational loads and to develop reliability standards.³ NERC's goal is to finish the first phase of this critical work this

² See Proclamation No. 11014, 91 Fed. Reg. 11439 (Mar. 4, 2026).

³ NERC, *Large Loads Action Plan Q1 2026 Update* (Apr. 2026), <https://www.nerc.com/globalassets/initiatives/large-loads-action-plan/llap-quarterly->

year. It is essential that NERC meet this deadline. I encourage all stakeholders to participate in NERC's process.

7. **Enhancing Transparency:** Today's orders provide regulators—the Commission and, critically, our state partners—and customers with data on how connecting large loads to the grid affects bills. Today's orders embody a commonsense approach: if a Network Upgrade is built to connect a large load to the grid, consumers should know who that upgrade was built for and what it cost.

8. Transparency is important because “who pays?” has been and continues to be a fraught and contentious question for large load interconnection. Stakeholders, including state regulators and the ratepayers that they represent, must know the costs, for whom they are being incurred, and how they are being allocated, to know that everyone is paying their fair share. Today's orders ensure that this information is public, accessible, and clear. State regulators in more than half of the country have enacted large load tariffs.⁴ Our action today helps them as they continue their critically important work.

9. The Commission's action today also addresses speculative load interconnection requests, which clog up load interconnection queues, divert resources, and distort forecasts. Under current rules, data centers can (and are incentivized to) “shop around” their prospective projects with different utilities to identify the fastest and cheapest location to connect. This wastes time and resources studying projects that are not real. Worse yet, it can inflate expected load growth by modeling projects that do not materialize, leading to double counting, inaccurate market signals, and unnecessarily high prices for consumers. Today, we target speculative projects by establishing escalating readiness requirements for distinct phases of the study process to deter duplicative or speculative requests for transmission service. I strongly encourage RTO/ISOs to pursue other improvements to load forecasts, such as using objective screening criteria like physical site control, to ensure that the data used to plan the grid is as accurate as possible.⁵

update-q1-2026.pdf.

⁴ See, e.g., National Association of Regulatory Utility Commissioners Supplemental Comments at 2-6; Edison Electric Institute Supplemental Comments at App. 9-13.

⁵ See Comm'r David Rosner, *Letter to the RTOs/ISOs on Large Load Forecasting* (Sept. 18, 2025), <https://www.ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting>.

10. **Fostering Innovation:** As I have said, to meet the moment, “a business-as-usual approach . . . will not suffice.”⁶ Building new infrastructure is difficult and costly, which delays efforts to connect large loads to the grid quickly, reliably, and cost effectively. This is doubly true when generation and load are planned and studied separately. Today’s orders push beyond this status quo.

11. First, today’s orders promote flexible transmission services—that is, non-firm service to a co-located load that is willing and able to limit withdrawals from the grid—in every RTO/ISO (*see Figure 2*). As we explained when we first created these transmission services in PJM for co-located loads, customers willing to embrace flexibility can reduce the need for Network Upgrades and generating capacity to serve a co-located load, which speeds up connecting to the grid *and* reduces costs for the co-located load *as well as* other retail customers.

12. Second, today’s orders recognize that extending these same transmission services to large loads that are *not* co-located but that may also be willing to limit their withdrawals from the grid can unlock even more efficiency. Just as for co-located loads, legalizing flexible transmission service options for more large load customers can speed interconnection, avoid constructing unnecessary transmission upgrades, reduce strain on the grid, and make power bills cheaper for everyone.

13. Finally, today’s orders embrace yet another innovation. Load and generation need not be co-located to reduce the number of Network Upgrades; in other words, literal co-location is not the only way to facilitate faster, more efficient, and more cost-effective connections to the grid. Rather, where a large load and an associated generator are *electrically proximate* (i.e., close together) *and studied together*, the reliability impacts on the grid may be more limited than if the load and generator are studied separately. Just like with co-location, more limited impacts on the grid mean, all else equal, fewer Network Upgrades, which makes connecting to the grid faster, more efficient, and cheaper for both the large load *and the associated generator*. That last point is key. To add new supply to the grid, we must create incentives for “Bring Your Own *New* Generation.” Today’s orders make BYONG faster and more efficient.

14. SPP has been a leader in showing how to push beyond the status quo. With its innovative HILLGA proposal, approved by the Commission in January,⁷ SPP leveraged the opportunity for speed and efficiency by studying load and generation together, and by creating a limited, expedited interconnection service to connect faster. By matching the generator’s output to the electrically proximate large load’s demand, the impacts to the

⁶ *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2026), (Rosner, Comm’r, concurring) at P 3.

⁷ *See Sw. Power Pool, Inc.*, 194 FERC ¶ 61,031 (2026).

grid are less than they otherwise would be, minimizing the need for time-consuming and costly Network Upgrades needed to connect. HILLGA is one solution that works for SPP, but today's orders direct other regions to follow SPP's lead in ways that work for them. Today's orders add a key tool by ensuring that all RTO/ISOs can study load and generation together.

15. The Commission's action today is an important step forward, but the Commission cannot accomplish this work alone. States are essential partners in this work. The Commission's actions here respect the long-standing jurisdictional line between federal and state authority provided by Congress and repeatedly affirmed by the Supreme Court. States retain exclusive jurisdiction to allocate the costs of FERC-jurisdictional transmission charges among their retail ratepayers, including co-located loads. States also hold the keys to energy infrastructure permits, so we rely on their decisions to ensure that needed transmission and generation get built. At a time when some large loads are retail customers that can consume as much energy as a small city, it is imperative that we work within our respective jurisdictions, but that we collaborate. I look forward to continued collaboration.

16. Today's orders *begin* an important dialogue with RTO/ISOs. As a potential next step, today's orders invite RTO/ISOs to respond by submitting proposals under FPA section 205. I cannot encourage this enough. I also encourage public utilities outside of RTO/ISOs across the country to do the same. The electric industry is rapidly evolving with regions experiencing and addressing these challenges in different ways. Many of the examples on which the actions in today's orders are based on stakeholders thinking creatively to develop solutions, and I welcome other new, innovative, and regionally tailored proposals that build on the four key pillars set forth today: (1) Protecting Consumers, (2) Safeguarding Reliability, (3) Enhancing Transparency, and (4) Fostering Innovation. Only by working together can we rise to the occasion and meet this once-in-a-generation moment to deliver the reliable and affordable energy on which we all depend. It will not be easy, but I remain optimistic and look forward to the path ahead.

For these reasons, I respectfully concur.

David Rosner
Commissioner

Figure 1

Four Pillars – FERC's Response to the Large Load ANOPR

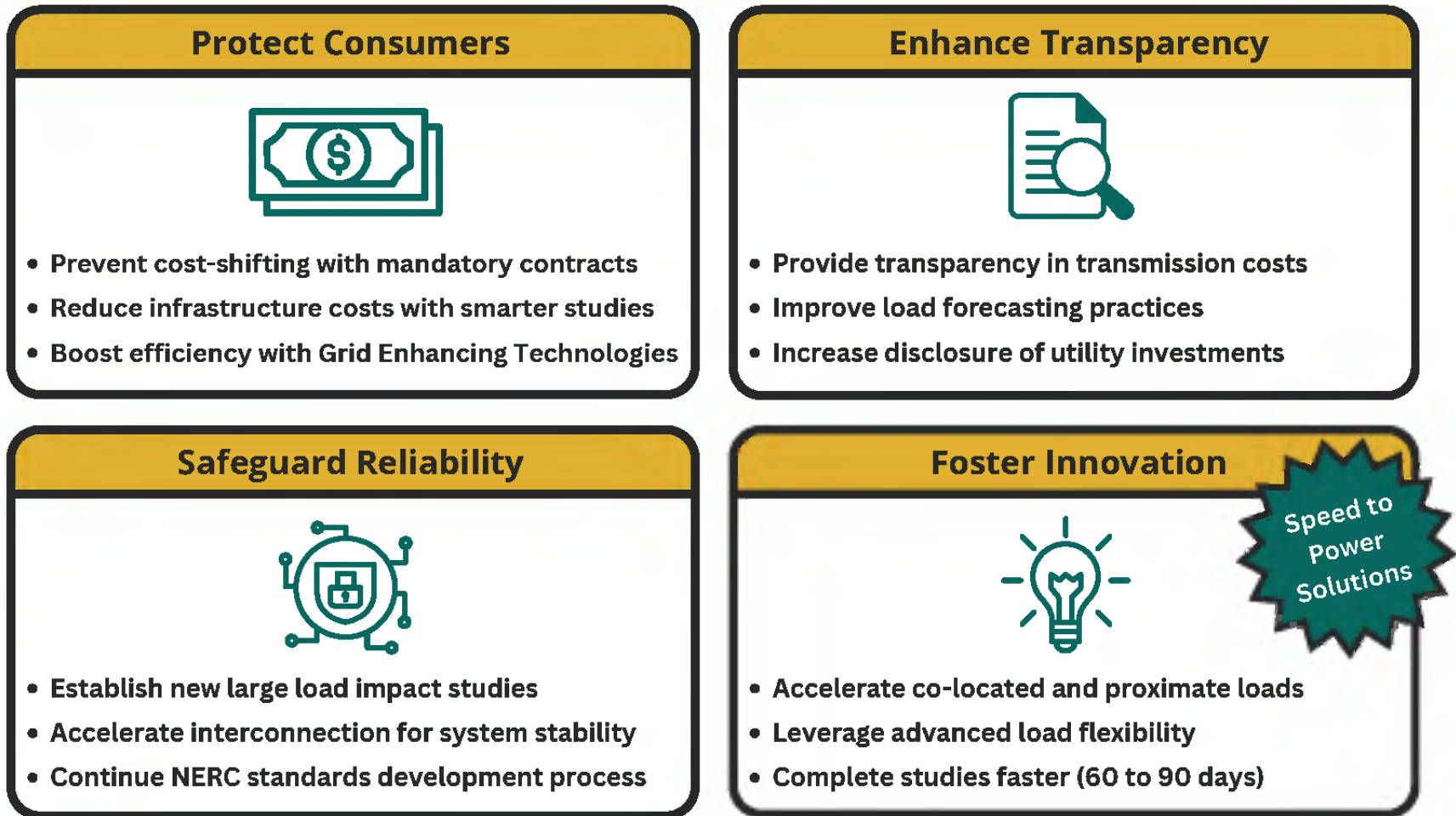
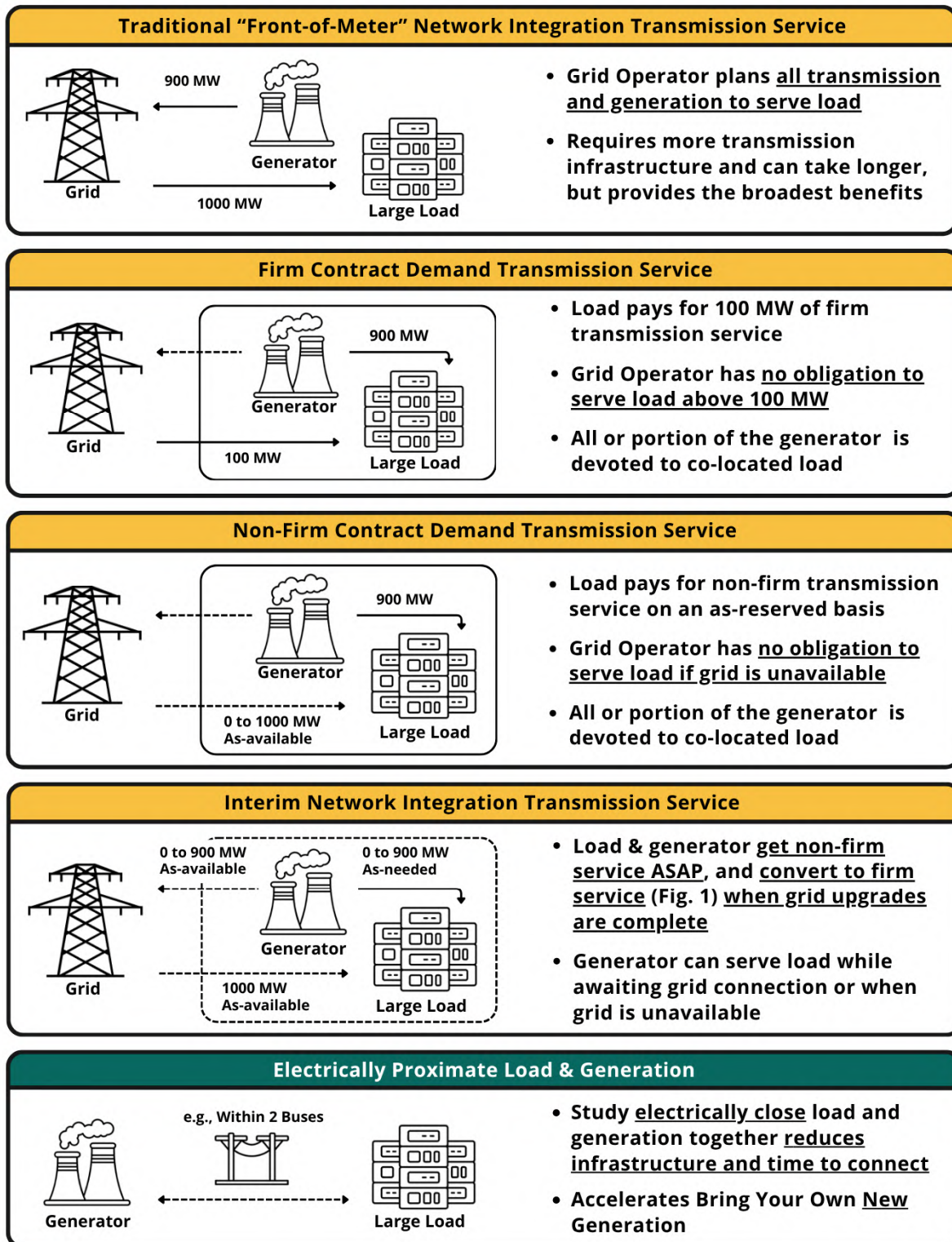


Figure 2

Large Load Interconnection: Transmission & Interconnection Service Innovation

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

Docket No. EL26-67-000

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company
PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company

Docket No. EL26-67-000

- 2 -

Silver Run Electric, LLC
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

(Issued June 18, 2026)

SEE, Commissioner, *concurring*:

1. Growing electricity demand underscores America's economic strength and the opportunities that come with it. And with new opportunities come new challenges. The pace and scale of emerging large loads create new circumstances that require us to adapt in how we build and manage the grid. Large and flexible loads can materially change system operations, for instance, as well as near-term planning needs, upgrade requirements, and how we allocate costs. Most existing systems were not designed to accommodate those changes—especially not at the pace needed to support AI growth and advanced manufacturing that are central to America's economic competitiveness. As a result, uncertainty over the operative rules and delays in interconnecting large loads can undermine reliability and investment and add unacceptable and avoidable costs.
2. Today, the Commission takes strong action within our jurisdictional sweep to address these and other challenges that large load growth poses to the interstate transmission system. Today's orders support both just and reasonable rates and speed to (reliable) power. I'm deeply grateful for the many commenters who shared their insight and ideas in this action. They let us build a record that highlights the need for clearer processes, better information, and faster analysis while our country moves new large load additions online. As we press forward in these dockets, I will be looking to continue building on the momentum already underway across the country to craft more practical, region-specific solutions that support timely action while protecting consumers. Our continued ability to deliver reliable and affordable electricity requires nothing less.
3. Today's orders speak for themselves. I write separately to briefly highlight two principles baked throughout them and that I believe must remain central as the Commission evaluates further steps.
4. First, these issues extend beyond the Commission. Creating efficient, predictable large load interconnection processes is a joint and overlapping task for us, other federal agencies, the States, and the RTOs/ISOs and utilities. My animating principle here is that we must use FERC's statutory authority to bring clarity to the parts of this national issue we own, and to complement and aid others as they tackle theirs. The very procedure the

Commission deploys today reflects that goal: Recognizing the value in region-specific approaches, we are directing individual action in each of the RTO/ISO regions and encouraging—strongly—proposals under section 205 of the Federal Power Act from transmission providers or other entities that are molded to their unique system needs.

5. Most critically, exercising our authority fully without hamstringing our regulatory and industry partners means respecting the States. States make many of the key decisions that affect how we manage large loads. States bring indispensable expertise over local conditions, siting needs, retail structures, and the resource decisions within their borders. And they have been hard at work pursuing the retail implications and other State-specific concerns that large load interconnection presents.¹ All this effort flows from the States' statutorily preserved role in regulating the power system. Today's order understands that limit—our power “extend[s] only to those matters which are not subject to regulation by the States.”² It also embraces the value in a statutory lens that views large load issues as an area of shared federal-State responsibility. As we require clear study and operational parameters for large load interconnection, we should remember that the nation's energy landscape is not monolithic. State and regional diversity is a strength, and today's orders know that the best solutions reflect differing system characteristics. Our action today is designed to support further State efforts in this urgent and fast-moving space, not override them.

6. Second, affordability must be at the forefront as we protect consumers from unnecessary costs in a time of rising demand. True, the Commission lacks authority over all the factors that drive electricity costs at the retail level. Today's orders recognize that. In response, the orders strive to aid the States in their front-line affordability duties by getting into their hands all relevant information about Commission-jurisdictional costs. As these matters move forward, I am particularly interested in continued feedback from the States on what information they most need to assess cost implications as new loads come online. Are the cost transparency measures we identify today sufficient, or are additional or more granular data needed for States to appropriately suballocate transmission costs among retail customers? Tools like alternative cost allocation structures, greater clarity in transmission service agreements, accounting for States' large-load-specific tariffs, and direct assignment in appropriate cases may help States ensure that retail consumers do not bear costs incommensurate with the benefits they receive.

¹ See EEI Supplemental Comments at Appendix 9 – 13 (listing pending and approved State large load tariffs).

² 16 U.S.C. § 824(a).

7. Moving to areas where the Commission has a more direct role in ensuring cost responsibility, we need to pull all the levers we have to keep rates fair and transparent. Today we reaffirm our responsibility to assign jurisdictional costs to the customers who drive or benefit from grid upgrades, not shift them onto families and small businesses. For instance, today's orders seek to reduce large-load driven network upgrade costs through alternative transmission technologies, or ATTs (also commonly called Grid Enhancing Technologies). In determining how best to meet the needs of this historic large load growth, technologies that can improve system capability faster than traditional upgrades and at lower costs deserve a hard look. ATTs may not be the best tool in every circumstance, but where they are they can support timely interconnections and avoid potentially tens or hundreds of millions of dollars in unnecessary network upgrade costs that would otherwise flow into transmission customers' bills.

8. So our approach today supports continuing the Commission's policy to roll most network upgrade costs—including those in the large load space—into the embedded-cost rate most transmission customers pay. But it includes an asterisk that this policy works for ratepayers only so long as we remain committed to pursuing technological innovations that keep those costs at a responsible and accountable level. Today's order thus calls for transmission providers to sufficiently evaluate ATTs to assess if and how they can meet large loads' interconnection needs. The answer may be yes or no in a given case. But if the transmission provider opts for traditional network upgrades, they must *demonstrate* why ATTs are not feasible or would not result in lower costs or a faster timeline for the large load interconnection customer. In short, the goal is to respect transmission providers' engineering judgments while protecting against upgrade costs when ATTs could solve transmission needs faster and with a lower bill.

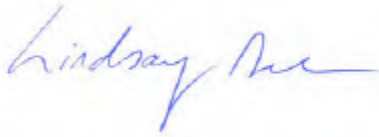
9. I am also sensitive to novel questions about cost shifting that interconnecting large load may present. Today's findings on cost recovery agreements between transmission owners and Eligible Customers are an important step in mitigating the risks of stranded assets if large loads prove speculative. We are also reducing unnecessary redundancy by allowing an Eligible Customer to meet its financial security requirements by relying on credit support or other financial security a large load customer may have posted under a retail agreement. As we gain more experience studying transmission service requests on behalf of large loads, it may become appropriate to further streamline financial security arrangements. Perhaps, for instance, cost -recovery agreements between a transmission owner and a large load customer itself could satisfy an Eligible Customer's financial security requirements. As we move forward, I'll be looking to ensure cost-recovery agreements contain fair and transparent measures to ensure the right costs get on the right bills. (Relatedly, the discussion about the full nature of transmission-related charges in our concurrent PJM Order on Rehearing, Clarification, Compliance, and Paper Hearing³

³ *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,209 (2026).

may prove relevant here: Real-world experience with new transmission services for co-located load may clarify if future action becomes needed to address potential cost shifts as Eligible Customers take new transmission services on behalf of large loads.⁴)

10. More generally, as we gain more experience as an industry and a country in getting large loads connected to the grid, I welcome bold proposals to keep affordability central. Large load growth presents a real opportunity to build a stronger, more capable, and more reliable electric system that can benefit all ratepayers. Meeting that opportunity at the pace we need and at an acceptable cost requires innovative thinking and fast action. I commend the States in their continued work in these areas. I urge the RTOs and ISOs to continue their good work as they respond quickly to today's orders. I also remain committed to moving forward within the Commission's statutory zone with clarity and decisiveness. I am proud to support the Commission's important steps today. And we all have more work ahead.

For these reasons, I respectfully concur.



Lindsay S. See
Commissioner

⁴ See *id.* P 456.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

Docket Nos. EL26-67-000

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company
PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company

Docket No. EL26-67-000

- 2 -

Silver Run Electric, LLC
Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

(Issued June 18, 2026)

CHANG, Commissioner, *concurring*:

1. In a series of orders today, the Commission initiates separate proceedings under Federal Power Act (FPA) section 206 to explore the impact of the increasing growth of large loads in Regional Transmission Organization (RTO) and Independent System Operator (ISO) regions. The preliminary findings in these orders, and the associated proposed reforms to RTO/ISO and transmission owner tariffs, could significantly change how loads procure, use, and pay for transmission service, with ramifications for RTO/ISO operations, planning, and markets. I write separately to emphasize the importance of building actionable records in these proceedings, particularly with respect to our consideration of customer protection, transmission service, and alternative transmission technology reforms.

I. Overview of Today's Orders

2. In each of today's orders to show cause, the Commission identifies a series of issues raised by the ongoing growth of large loads, directs briefing on whether existing tariffs remain just and reasonable in light of those developments, and describes possible solutions to those issues if the Commission ultimately concludes that the relevant tariffs are unjust and unreasonable. Each order is directed to a specific RTO/ISO and relevant transmission owners that play a role in interconnecting large loads to the Commission-jurisdictional transmission system. The Commission does not pursue the broad assertion of jurisdictional authority contemplated in the Advanced Notice of Proposed Rulemaking, which I hope assuages concerns raised by our state colleagues that the Commission ought not encroach upon matters properly left to their jurisdiction.¹

¹ I will do my part to ensure that the Commission continues to be a collaborative partner to our state counterparts, other federal agencies, and the industry as we seek to address this wide-ranging challenge. Accordingly, I welcome feedback from our state colleagues and others if they believe the Commission's preliminary findings raise jurisdictional concerns.

3. Broadly summarized, each order seeks regional input on a specific list of issues: (1) the clarity and consistency of existing rules governing how each RTO/ISO and its relevant transmission owners analyze the impact of providing transmission service to Eligible Customers on behalf of large loads; (2) whether each RTO/ISO tariff requires reforms to mitigate the risk of cost shifting among wholesale transmission customers; (3) whether each RTO/ISO tariff (other than PJM) requires additional clarity regarding the provisions addressing co-located generation and load arrangements; (4) the potential extension of new firm and non-firm transmission services to co-located load, load with behind the meter generation, and other flexible loads; and (5) the need for reforms, modeled on Southwest Power Pool, Inc.'s High Impact Large Load Generation Assessment concept, to facilitate a process through which a generator may temporarily serve a co-located or electrically proximate load until interconnection and transmission service is available. The Commission also invites each region to submit FPA section 205 filings that can address each issue identified in the orders, thereby resolving the Commission's concerns.

II. The Commission Needs Good Records to Ensure Reasoned Decision-Making

4. I first want to emphasize that the Commission needs active participation from interested stakeholders to develop thorough records in each region. The Commission cannot make reasoned decisions about whether reforms might be needed without an accurate understanding of the existing processes, which differ by region. Because the Commission is acting via FPA section 206 rather than generically through a rulemaking, the issues addressed by these orders will be subject to *ex parte* restrictions across the RTOs/ISO regions, including with our state colleagues whose regulation can and will directly affect the individual transmission owners that need to comply with the orders issued today. This will limit the Commission's ability to engage in informal fact-finding and discussions with regional stakeholders, and thus, it is even more essential that the record in each region fully reflects the views of all interested parties.

5. Second, I highlight three issues below that will be especially important to the success of this effort, and I hope that interested parties will take particular care in helping the Commission address those issues. Importantly, I recognize that the record established in each RTO/ISO region will (and should) differ, which will allow the Commission to ensure any required changes to an RTO/ISO's tariff are appropriately tailored to that region's needs.

III. The Commission Needs to Pursue Meaningful Customer Protection

6. The FPA is fundamentally a customer protection statute,² and the Commission has an obligation to ensure that the rates that wholesale and transmission customers pay are

² See, e.g., *Mun. Light Bds. Of Reading and Wakefield v. FPC*, 450 F.2d 1341,

just and reasonable. Rapid large load growth has strained planning and resource procurement processes around the country, as transmission owners, load serving entities, and generators accelerate the building of new infrastructure needed to serve these new loads. As we develop the new infrastructure, many have raised concerns about whether these costs are being fairly assigned to new and existing customers, whose benefits must be commensurate with the costs they pay. While individual states have been exploring or using various approaches to protect *retail* customers against unjustified cost shifts, the Commission to date has not initiated any proactive exploration of how to protect *wholesale* customers against unjustified cost shifts. I am laser-focused on this issue because we should not create unjustified costs for consumers in our efforts to connect and serve large loads.

7. In today's orders, the Commission launches an inquiry into whether existing RTO/ISO tariffs include adequate mechanisms to mitigate the risk of undue cost shifting among transmission customers. To address this risk, the Commission preliminarily identifies a two-part solution: (1) that each RTO/ISO post public information about the amount of new large loads seeking to connect to the RTO's/ISO's transmission system, any Network Upgrades identified in the local transmission planning process to serve those loads, and the costs of those Network Upgrades; and (2) that each RTO/ISO adopt a *pro forma* cost recovery agreement to help ensure that Eligible Customers serving large loads bear the risk and are ultimately responsible for costs incurred to provide transmission service. I strongly support this effort to provide additional transparency regarding jurisdictional transmission service requests and the costs associated with providing transmission service to the requesting parties, as the Commission cannot effectively execute its statutory responsibilities without sufficient understanding of the costs that feed into jurisdictional rates.

8. Exploring how agreements between transmission owners and Eligible Customers can protect *wholesale* customers against cost shifts is important. However, as I have previously explained, bilateral agreements that simply provide transmission revenue contributions untethered from any assessment of the actual cost of providing transmission service induced by individual large loads may be insufficient to adequately protect other customers against unjustified cost shifts.³ It is therefore important that the resulting regulatory and rate design are not limited to a pre-defined solution set, and that parties provide the Commission with comprehensive records outlining various and innovative

1348 (D.C. Cir. 1971) (stating that the FPA's "primary aim is the protection of consumers from excessive rates and charges").

³ E.g., *PECO Energy Co.*, 193 FERC ¶ 61,148 (2025) (Comm'r Chang, *concurring*); *Commonwealth Edison Co.*, 194 FERC ¶ 61,109 (2026) (Comm'r Chang, *concurring*).

approaches to protect customers. I am encouraged by the continued development of the ANOPR record on this subject,⁴ innovative solutions being developed at the state level,⁵ and a growing body of thoughtful analyses and proposed approaches to provide customer protection for costs driven by large load growth.⁶ Without prejudging any particular proposed solution, the Commission needs a robust record in each docket and each region to ensure we establish the right cost shift protections for wholesale customers, including but not limited to the commitments outlined in the Ratepayer Protection Pledge.⁷

9. I support initiating our own review of customer protection approaches, rather than simply relying on voluntary commitments that may fall short of optimal protection, because the Commission has the opportunity and obligation to get this issue right. I therefore encourage interested parties to assist the Commission in that effort by clearly and comprehensively explaining the benefits and tradeoffs of alternative customer protection approaches. How power infrastructure costs will be assigned across Eligible Customers that serve large loads and other customers is at the core of the efforts we initiate today.

IV. The Commission Needs to Understand the Implications of Extending New Transmission Services to Additional Loads and Regions

10. The orders also preliminarily find that the Commission should extend the transmission services developed in the PJM co-location proceeding – Interim NITS, Firm Contract Demand, and Non-Firm Contract Demand – to new types of load and new

⁴ E.g., *Interconnection of Large Loads to the Interstate Trans. Sys.*, Supplemental Comments of FirstEnergy Svc. Co., Docket No. RM26-4-000 (filed June 5, 2026); *id.*, Comment of the Harvard Electricity Law Initiative, Docket No. RM26-4-000 (Apr. 15, 2026); *id.*, Supplemental Comments of WIRES, Docket No. RM26-4-000 (Mar. 30, 2026).

⁵ E.g., Utility Dive, *Microsoft seeks Nevada tariff to shield ratepayers from data center costs* (June 8, 2026), available at <https://www.utilitydive.com/news/microsoft-seeks-nevada-tariff-to-shield-ratepayers-from-data-center-costs/822250/>.

⁶ E.g., Travis Kavulla, *How Will Data Centers Pay for Power?*, American Affairs (May 2026), available at <https://americanaffairsjournal.org/2026/05/how-will-data-centers-pay-for-power/>; Electricity Customer Alliance, *A Customer-Centric Agenda for the Federal Energy Reg. Comm'n* (Jan. 2026), available at <https://lnkd.in/em-apfuQ>; Grid Strategies, *Federal Transmission Pricing Vol. 2, Options for Ensuring Affordability in an Era of High Load Growth* (June 2026), available at <https://gridstrategiesllc.com/project/federal-transmission-pricing>.

⁷ Proclamation No. 11014, 91 Fed. Reg. 11439 (Mar. 4, 2026).

regions. These new transmission services represent a fundamental paradigm shift from the traditional network service and point-to-point transmission service models established in Order No. 888 that have been used across the country for the last three decades. While these services have the potential to facilitate more efficient use and build out of the transmission system, they also contemplate running the system “tighter” than we have done in the past, potentially with more loads on the system served by co-located or behind-the-meter generation, and potentially more use of batteries, load control systems, and backup resources to manage demand during system peaks or other stressed conditions. While it is important to identify innovative solutions that can adapt to the needs of the system, the Commission and grid operators must also be careful not to implement changes that create unforeseen reliability risks. Ultimately, we must find the proper balance (and I would argue we are exploring a *new* balance) between costs of investments versus reliability.

11. The Commission’s experience in the PJM co-location proceeding highlights the complexities and challenges of introducing these new transmission services, which have significant ramifications for system operations, transmission planning, grid reliability, market dispatch, resource adequacy, and cost allocation. As the Commission considers whether to expand these transmission services to new types of load and new regions, I encourage commenters to address what impacts the introduction of new firm and non-firm transmission products would have in their regions, as well as any relevant characteristics that might distinguish their regions from the Commission’s findings in the PJM co-location docket. Ultimately, this topic will have direct long-term impacts on how future transmission systems will be planned and configured, how efficiently future power markets will operate, and how customers will respond to prices and system needs. Therefore, I am specifically interested in understanding how extending the new transmission services might affect individual suppliers or customers, as well as how existing systems or processes might be affected by these new services. I am open to understanding how these services might be helpful to a region or that they may create problems not yet anticipated.

V. The Orders Recognize the Importance of Evaluating Advanced Transmission Technologies

12. Lastly, today we preliminarily find that each RTO/ISO’s tariff is unjust and unreasonable because the tariff lacks clear and consistent provisions requiring the evaluation of alternative transmission technologies as potential solutions to accommodate an Eligible Customer’s request for transmission service on behalf of a large load. Specifically, it is important for RTO/ISOs and transmission owners to evaluate whether alternative transmission technologies are feasible in reducing the cost of transmission system upgrades or allow for a faster timeline for accommodating the transmission service request. As many transmission owners have explored various alternative

technologies in pilot projects,⁸ it is time to roll out all available technologies to reduce risks and costs for customers, as well as help the industry continue to develop new technologies that can increase the robustness of our transmission system while protecting customers from higher costs.

VI. Conclusion

13. Today's orders address some of the most consequential issues currently in the industry and before the Commission. I hope that these proceedings provide vehicles through which the Commission can provide much-needed clarity and direction, and it is imperative that we build strong and comprehensive records on each issue in each region to inform our decision-making. I therefore encourage all interested parties to fully engage and help the Commission navigate these complex, multi-faceted challenges. Our success will ultimately be measured by our shared ability to deliver reliable and affordable power to all customers, to ensure new loads can interconnect in a timely fashion while paying their fair share of system costs, and to protect existing customers against adverse reliability or economic impacts.

⁸ See, e.g., *Increasing Mkt. and Planning Efficiency Through Improved Software*, Effective Congestion Mitigation with Transmission Topology Optimization at Alliant Energy and ATC, Docket No. AD10-12-016, *available at* <https://www.ferc.gov/media/effective-congestion-mitigation-transmission-topology-optimization-alliant-energy-and-atc> (Alliant and ATC were able to save customers approximately \$24 million over a 12-month period through the use of topology optimization); Pablo Ruiz and Derek Brown, "Reliable and Efficient Congestion Mitigation Using Transmission Reconfigurations," NewGrid and Evergy presentation (Oct. 2022), *available at* <https://www.spp.org/Documents/67968/SAG%20Meeting%20Materials%2020221007.zip> (identifying reconfigurations, had they been implemented, which could eliminate 98% of overloads and reduce congestion costs by 85% for congestion patterns associated with 10 significant constraints on Evergy's system); Pacific Gas & Electric Press Release, *PG&E and Smart Wires Enhance Grid Reliability, Capacity for Data Centers in San Jose* (May 28, 2025), *available at* <https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-and-Smart-Wires-Enhance-Grid-Reliability-Capacity-for-Data-Centers-in-San-Jose/default.aspx> (describing PG&E's deployment of advanced power flow control devices were able to mitigate thermal overloads by up to 34%, enabling an additional 100 MW of firm power delivery over existing lines at a congested substation).

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For these reasons, I respectfully concur.

A handwritten signature in black ink, appearing to read "Judy Chang", with a long horizontal flourish extending to the right.

Judy W. Chang
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.

Docket No. EL26-67-000

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.
Allegheny Electric Cooperative, Inc.
American Transmission Systems, Incorporated
Appalachian Power Company
Atlantic City Electric Company
Baltimore Gas and Electric Company
Commonwealth Edison Company
Commonwealth Edison Company of Indiana, Inc.
Dayton Power and Light Company
Delmarva Power & Light Company
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
Essential Power Rock Springs, LLC
Hudson Transmission Partners, LLC
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kentucky Power Company
Keystone Appalachian Transmission Company
Kingsport Power Company
Linden VFT, LLC
Mid-Atlantic Interstate Transmission, LLC
Monongahela Power Company
Neptune Regional Transmission System, LLC
NextEra Energy Transmission MidAtlantic Indiana, Inc.
Ohio Power Company
Ohio Valley Electric Corporation
Old Dominion Electric Cooperative
PECO Energy Company
PPL Electric Utilities Corporation
The Potomac Edison Company
Potomac Electric Power Company
Public Service Electric and Gas Company
Rockland Electric Company
Silver Run Electric, LLC

Docket No. EL26-67-000

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Trans-Allegheny Interstate Line Company
Transource West Virginia, LLC
UGI Utilities, Inc.
Virginia Electric and Power Company
Wabash Valley Power Association, Inc.
Wheeling Power Company

(Issued June 18, 2026)

LACERTE, Commissioner, *concurring*:

1. I support today's fleet of show cause orders. We are at an inflection point in the history of American energy infrastructure. The extraordinary and rapid growth of large loads in RTOs and ISOs is faster than the current system can handle. This order charts a course for addressing the potential gaps and shortcomings in PJM's Tariff that need to be resolved to appropriately respond to this growth, as informed by careful review of the thousands of pages of comments received in response to the advance notice of proposed rulemaking (ANOPR).¹ I write separately to underscore my expectation for RTOs and ISOs, including PJM, to timely submit their robust, thoughtful, and region-specific proposals to address the concerns that we have preliminarily identified in their respective tariffs and agreements. By harnessing your region-specific expertise and creativity to bring tailored solutions to the table, together we can efficiently, reliably, and affordably integrate large load, co-located load and generation and/or storage, as well as electrically proximate large load onto the transmission system. I also support the use of alternative transmission technologies to unlock every megawatt of existing capacity from our current transmission system. We have the technology. We should use it now to enable faster interconnection of large loads, lower costs to customers, and help prevent cost shifting.

2. To that end, and in light of our action in today's orders, I also ask the state public utility commissions—whether they have already approved large load retail tariffs, are in the process of crafting large load retail tariffs, or have yet to embark on this essential tariff design process—to take a hard look and ensure their large load retail tariff provisions insulate ratepayers from the negative impacts of data center growth. Additionally, I expect PJM to design proposals in response to this show cause order that dovetail with the efforts on the retail side to implement the Ratepayer Protection Pledge,

¹ *Interconnection of Large Loads to the Interstate Transmission System*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000, (Oct. 23, 2025) (ANOPR); *see also* Letter from Chris Wright, Sec'y, U.S. Dep't of Energy (Oct. 23, 2025) (Secretary's Letter).

protect customers, and ensure that large loads cover the costs they incur to integrate with the grid.

3. The stakes here could not be higher and every gambler knows that the secret to surviving is knowing what to throw away and knowing what to keep.² Today's orders do exactly that—adopting thoughtful proposals that position our nation for success, driving meaningful change, and rejecting the gridlock, half-measures, and failure to plan that have gone on for far too long. The data center odyssey that we embarked upon first with PJM, then SPP, we now aggressively extend to all the RTO/ISO regions.³ Enabling the swift and efficient interconnection of large loads to the transmission system while maintaining affordability, reliability, commitment to open access, competitive principles and cooperative federalism, will only be achieved through consistent, coordinated action and persistence. But without that first step,⁴ there is no direction, no forward momentum, no journey, and no way to arrive at our future destination. In the show cause orders we issue today, the Commission takes a series of long strides towards our ultimate large load interconnection destination: we make preliminary findings that the RTO/ISO tariffs, including PJM may be unjust and unreasonable and/or unduly discriminatory or preferential because they lack features necessary to timely, reliably, and safely interconnect and serve new large loads in a way that produces just and reasonable rates.

4. I commend each commentor for their robust and ongoing responses to the concerns that Secretary Wright and the Commission raised in the ANOPR proceeding. The comments helped us identify the common issues, common solutions, and individual differences among the RTOs/ISOs. We heard a plea for broad flexibility and regionally tailored solutions. And we will strive to work towards those solutions, not through top-down, one-size-fits-all mandates, but through consideration of region-specific proposals. And we endeavor to support an appeal for federal policies that build upon rather than disrupt current and planned developments, reflecting state and local processes and stakeholder efforts. Through these individually tailored and region-specific show cause orders, we are delivering to ensure that our transmission system can accommodate new large loads in a timely, safe, and reliable manner. And, importantly, in a manner that

² Kenny Rogers, *The Gambler* (United Artists Records 1978).

³ *Interconnection of Large Loads to the Interstate Transmission System*, 195 FERC ¶ 61,045 at P 2 (2026) (Order Regarding Intent to Act) (citing PJM Co-Location Order, 193 FERC ¶ 61,217; SPP HILL Order, 194 FERC ¶ 61,031; *Commonwealth Edison Co.*, 194 FERC ¶ 61,181 (2026); *Tri-State Generation and Transmission Ass'n*, 193 FERC ¶ 61,070 (2025); *Duke Energy Carolinas, LLC*, 193 FERC ¶ 61,237 (2025)).

⁴ Admittedly, we are further down the road in some regions as compared with others.

ensures benefits and protection for all customers. Affordability remains a top concern as we proceed forward.

5. The collective voices in the ANOPR comments have shaped our decision to issue six separate individually tailored and region-specific show cause orders, rather than a proposed final rule *at this time*. But the success of the next phase of this journey rests with you, PJM, and your stakeholders. We are directing you to expeditiously bring forward for our consideration your novel, region-specific solution(s). Time is of the essence. By inviting you to proceed under FPA section 205, we are giving you significant perks: the benefits of first wielder of the pen and the relatively capacious standard under FPA section 205 that allows us to accept a potentially broad range of proposals provided they are shown to be just and reasonable and not unduly discriminatory or preferential.⁵ We are even giving you flexibility to propose the implementation date for your innovative proposals. But such freedom comes with great and concomitant responsibility.

6. This is not a time to be cavalier and dodge the urgent need to meet the moment. While this is a long journey, even so, we must continue to move at breakneck pace to win the AI race. So let me be direct. If you choose not to submit timely, reasonable, non-discriminatory or preferential, comprehensive, and substantiated proposal(s), as directed and as required under our applicable statutes, your deficient response will not go unnoticed. I am prepared to play jurisdictional hardball, if needed.⁶ This Commission has appropriately exercised considerable restraint in asserting the full scope of our jurisdiction in these orders. However, the Commission has very broad jurisdiction over transmission that we will not hesitate to utilize as necessary to ensure that we meet our objectives in all show cause proceedings, including this PJM proceeding we initiate here. If we find your Tariff is in fact unjust and unreasonable and unduly discriminatory or

⁵ See, e.g., *NRG Power Mktg, LLC v. FERC*, 862 FERC 108, 105 (D.C. Cir. 2017) (FERC may not employ a rate design that follows “a completely different strategy” than, or is “methodologically distinct” from, a proposed rate) (internal quotations omitted); *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (stating that a proposal under FPA section 205 “need not be the only reasonable methodology, or even the most accurate”); *City of Winnfield v. FERC*, 744 F.2d 871, at 874-875 (D.C. Cir. 1984) (comparing the respective authorities of the Commission and public utilities under sections 205 and 206).

⁶ 16 U.S.C. § 824(b); *New York v. FERC*, 535 U.S. 17 (2002) (“There is no language in the statute limiting FERC’s *transmission* jurisdiction to the wholesale market[.]”) (emphasis in original); *id.* at 20 (stating that “the FPA authorizes FERC’s jurisdiction over interstate transmissions, without regard to whether the transmissions are sold to a reseller or directly to a consumer[.]”).

preferential, any failure on your end to provide a sufficient FPA filing or filings to address the large-load-related concerns that we have identified will result in the Commission dictating the solutions for you. I say this not as a threat, but as a statement of duty. While you may not like our remedies—I have often said that the federal government generally does not come up with the best solutions—this is an outcome we are prepared to pursue given the gravity of the moment and our statutory obligation. Notwithstanding our readiness to step in, it greatly benefits everyone for you to come up with an approach tailored to your region.

7. I will end my concurrence where I began: We have heard your concerns, and, let me underscore, now is the time for you to heed ours. This is an extraordinarily consequential proceeding. The stakes for reliability, for affordability, and for the American ratepayer could not be higher. We owe it to the public to get this right. I look forward to reviewing and acting as expeditiously as possible on your responses to this show cause order, which I expect will include an FPA section 205 proposal or proposals.

8. For these reasons, I respectfully concur.

David LaCerte
Commissioner

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EXHIBIT G



EXECUTIVE OFFICE OF THE
GOVERNOR

RON DESANTIS
46TH GOVERNOR OF FLORIDA



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GOVERNOR RON DESANTIS SIGNS LAW TO PROTECT FLORIDIANS

FROM SUBSIDIZING DATA CENTERS

May 7, 2026

LAKELAND, Fla. —Today, Governor Ron DeSantis signed SB 484, which protects ratepayers, the environment, and local communities from harm caused by hyperscale data centers.

“Today in Lakeland, I signed legislation to protect our citizens and communities from hyperscale data centers. These are much-needed protections for taxpayers and our natural resources,” **said Governor Ron DeSantis**. “SB 484 ensures that local governments maintain the authority to reject data center development in their communities, prevents data center costs from being passed on to consumers, including electricity costs, and protects Florida’s water resources from data center consumption.”

Governor Ron DeSantis signed SB 484. The bill:

- **Protects Ratepayers**
 - Prohibits utilities from passing data center costs, including electricity costs, onto residential and small business customers.
 - Requires large-scale users to pay their full cost of service.
 - Prevents financial risk from being shifted to the public.
- **Empowers Local Communities**
 - Preserves local authority over zoning, permitting, and land use.
 - Allows communities to set stricter standards or deny projects.
 - Ensures data centers are properly classified and regulated.
- **Increases Transparency and Security**
 - Requires public disclosure of data center development deals after the exemption period.
 - Establishes clear definitions in law to prevent loopholes.
 - Prohibits utilities from serving data centers owned or controlled by foreign countries of concern.
- **Strengthens Infrastructure and Environmental Standards**
 - Creates a dedicated permitting process for large-scale data centers.
 - Allows use of reclaimed water as part of permitting.
 - Requires major modifications to be treated as new applications.

###

EXHIBIT H

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

)

Docket No. ER26-____-000

**PROPOSAL OF PJM INTERCONNECTION, L.L.C.
TO ESTABLISH INTERIM RESOURCE ADEQUACY SERVICE AND A LARGE
LOAD REGISTRY TO ADDRESS SYSTEM RELIABILITY**

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

Ryan J. Collins
Vivian W. Chum
Wright & Talisman, P.C.
1200 G Street, NW, Suite 600
Washington, D.C. 20005
(202) 393-1200
collins@wrightlaw.com
chum@wrightlaw.com

Mark J. Stanisz
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-8800
mark.stanisz@pjm.com

Attorneys for PJM Interconnection, L.L.C.

August 13, 2026

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1200 G Street, N.W., Suite 600
Washington, D.C. 20005-3898
Phone: 202.393.1200
Fax: 202.393.1240
wrightlaw.com

August 13, 2026

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER26-____-000
Proposal to Establish Interim Resource Adequacy Service and a Large Load
Registry to Address System Reliability

Dear Ms. Reese:

PJM Interconnection, L.L.C. (“PJM”), pursuant to section 205 of the Federal Power Act (“FPA”), 16 U.S.C. § 824d, hereby submits revisions to the Reliability Assurance Agreement Among Load Serving Entities (“RAA”) and the PJM Open Access Transmission Tariff (“Tariff”)¹ to establish Interim Resource Adequacy Service (“IRAS”)—a service to be implemented by PJM solely during periods when there are insufficient resources to reliably meet demand in real time operations. When triggered by system conditions, IRAS will enable PJM to prioritize load reduction in zones/areas where New Large Loads² have not brought their own new capacity or had their capacity needs

¹ In the context of revisions proposed in this filing, the Tariff will be referred to as “proposed Tariff,” and the RAA will be referred to as “proposed RAA.” Capitalized terms not otherwise defined herein shall have the meaning as defined in the Tariff, Amended and Restated Operating Agreement of PJM (“Operating Agreement”), RAA, and Consolidated Transmission Owners Agreement.

² Proposed Tariff, Definitions – New Large Load (“‘New Large Load’ shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1, 2027, or (b) incremental load in-service after June 1, 2027, that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then New Large Load shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met or (b) incremental load in-service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met that increases the existing end-use customer load at

Honorable Debbie-Anne A. Reese

August 13, 2026

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covered through the Reliability Backstop Procurement (“RBP”).³ New Large Loads can avoid this condition on taking transmission service by bringing new capacity to the system, as described below. The authority sought herein would only be invoked in those situations where PJM determines that the available economic real-time supply may be insufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits (“IROL”) within prescribed limits and prevent cascading outages.⁴

The proposed IRAS framework and the other enclosed revisions fall squarely within the Federal Energy Regulatory Commission’s (“Commission”) established transmission jurisdiction and wholesale jurisdiction and has been carefully designed to respect the cooperative federalism approach established under the FPA and animating several other recent landmark Commission determinations, including the large load show cause proceedings.⁵ As such, IRAS respects existing bright-line divisions between retail

a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load.”).

³ Although the proposed IRAS framework and other revisions proposed herein may refer to the RBP, the two filings are independent of each other. In short, , IRAS can and should be accepted and made effective as requested.

⁴ The North American Electric Reliability Corporation (“NERC”) defines an Interconnection Reliability Operating Limit as “[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.” *Glossary Terms*, North American Electric Reliability Corporation, <https://www.nerc.com/glossary-of-terms?alpha=I> [<https://perma.cc/TZ9W-MZ4K>] (last visited Aug. 11, 2026) (defining Interconnection Reliability Operating Limit); *IRO-009-2 – Reliability Coordinator Actions to Operate Within IROLs*, North American Electric Reliability Corporation, <https://www.nerc.com/globalassets/standards/reliability-standards/iro/iro-009-2.pdf> [<https://perma.cc/6MLX-HBHM>] (last visited Aug. 11, 2026) (The appropriate NERC Standard: IRO-009-2’s purpose is “[t]o prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).”).

⁵ See *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025) (“December 2025 Show Cause Order”); *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211 (2026) (“June 2026 Order to Show Cause”).

Honorable Debbie-Anne A. Reese

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and wholesale jurisdiction over transmission and distribution. It is an example of a federal regime encouraging (but not mandating) states to re-evaluate load reduction plans, which are traditionally in the state jurisdictional bailiwick, while providing PJM the necessary tools to address situations where regional resource adequacy shortfalls would jeopardize reliability.⁶ In this regard, it is an example of the federal regime helping to effectuate state decisions associated with the rates, terms, and conditions of retail service. Moreover, the IRAS framework, as proposed here, was developed following consultations and discussions with states and stakeholders (through the Critical Issue Fast Path (“CIFP”) process), and the proposal is intentionally designed to avoid conflicts with state authority and regimes by leaving retail load reduction plans and retail cost allocation to state-level entities, while offering non-mandatory options under the federal tariff to aid collection and settlement of compensation for IRAS.

As further evidence of this federal-state division of labor, PJM anticipates participating in efforts to develop standardized regulatory tools and model retail tariff structures that individual state commissions may consider as they address the integration of new large loads and otherwise decide whether and how to act in response to the evolving federal wholesale landscape, inclusive of the IRAS filing.

To support the IRAS framework, PJM is also proposing three foundational revisions in this filing. First, PJM is proposing revisions to the RAA⁷ to clarify a Load Serving Entity’s (“LSE”) obligation to bring new capacity in an amount that equals or

⁶ Under PJM’s existing authority, it may receive load reduction plans from Electric Distributors and other Members. *See, e.g.*, Operating Agreement, sections 10.4, 11.3.1(e).

⁷ Proposed RAA, section 7.8.

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exceeds its New Large Loads' peak load or be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response. This principle lays the foundation for the IRAS paradigm in PJM that facilitates large load interconnections in a manner similar to the Southwest Power Pool's ("SPP") Conditional High Impact Large Load Service ("CHILLS") construct, which "allows transmission customers serving [a certain category of load called High Impact Large Loads] to reliably receive transfers of energy [subject to curtailment and interruption] until sufficient designated resources and/or network upgrades are in place to support long-term, firm transmission service[,]" where terms and conditions of service are "intended to incentivize transmission customers . . . to obtain the designated resources and/or complete the network upgrades needed to procure long-term firm transmission service through existing tariff processes."⁸ In addition, this principle is consistent with the Ratepayer Protection Pledge introduced in March 2026⁹ and recently expanded in July 2026,¹⁰ which assures that New Large Loads will, at a minimum,

⁸ June 2026 Order to Show Cause, 195 FERC ¶ 61,211.

⁹ *Ratepayer Protection Pledge*, The White House (Mar. 4, 2026), <https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/> [<https://perma.cc/N8PH-K82T>] ("Ratepayer Protection Pledge").

¹⁰ *President Trump's Ratepayer Protection Pledge Secures American AI Dominance, Protects Consumers*, The White House (July 23, 2026), <https://www.whitehouse.gov/releases/2026/07/president-trumps-ratepayer-protection-pledge-secures-american-ai-dominance-protects-consumers/> [<https://perma.cc/9VDB-B4EH>] ("Ratepayer Protection Pledge Announcement"); *Data centers pay their way. Ratepayers pay theirs.*, The White House, <https://www.whitehouse.gov/ratepayer-protection-pledge/> [<https://perma.cc/3WBQ-RXW4>] (last visited on Aug. 12, 2026) ("July 2026 Ratepayer Protection Pledge Update") (identifying 282 utilities, cooperatives, data centers, and 23 governors that joined the Ratepayer Protection Pledge, including 38 data centers: Aligned Data Centers, LLC; Amazon.com, Inc.; Beale Infrastructure Group, LLC; CleanSpark LLC; Cloud HQ LLC; Cologix, Inc.; Compass Datacenters, LLC; Core Scientific, Inc.; CoreWeave, Inc.; Corscale, LLC; Crusoe Technologies LLC; CyrusOne, Inc.; DataBank Holdings, Ltd.; Digital Realty Trust, Inc.; EdgeConnex Inc.; EdgeCore Digital Infrastructure (d/b/a EdgeCore Internet Real Estate, LLC); Equinix, Inc.; Google (d/b/a Alphabet Inc.); Iron Mountain Incorporated; Meta Platforms, Inc.; Microsoft Corporation; Nebius Group N.V.; NTT Global Data Centers (d/b/a NTT DATA, Inc.); OpenAI, L.L.C.; Oracle Corporation; Oppidan Connect Data Centers (d/b/a Oppidan Investment Company); Prologis, Inc.; Quality Technology Services, LLC; Rowan Digital Infrastructure Pty. Ltd.; Skybox Datacenters, LLC; STACK Infrastructure, Inc.; Starwood Digital Ventures (d/b/a Starwood Capital Operations, LLC); Stream

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“build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands, paying the full cost of those resources whether by building, or buying from, new or otherwise additive power plants” because it “advances self-sufficiency and protects Americans from higher prices.”¹¹

Second, PJM is proposing revisions to the RAA to establish a Large Load Registry—a database of information pertaining to Large Loads that will be established and maintained by PJM. The Large Load Registry, while reliant on information provided by others, will aid PJM in administering recent resource adequacy initiatives, including IRAS, as well as likely useful in the implementation of other Large Load-related initiatives.¹² Third, PJM is proposing to revise its Tariff and the RAA to include definitions of Large Load and New Large Load.¹³

In addition to those revisions, PJM is proposing, beginning with the 2029/2030 Delivery Year, to exclude certain New Large Loads from the Variable Resource Requirement (“VRR”) Curve to protect residential customers from capacity price

Data Centers, L.P.; Switch, Inc.; T5Data Centers, LLC; TA Realty LLC; Vantage Data Centers Management Company, LLC; and x.AI LLC).

¹¹ Ratepayer Protection Pledge.

¹² In response to the Commission’s show cause directives related to Large Loads, PJM is evaluating how to efficiently and cost effectively integrate Large Loads, including Large Load-specific procedures for interconnection studies, processing transmission service requests, and providing transmission service without cost shifting. *PJM Interconnection, L.L.C.*, Motion of PJM Interconnection, L.L.C. to Hold Proceeding in Abeyance and Request For Shortened Answer Period and Expedited Treatment, Docket No. EL26-67-000, at 5-7 (July 28, 2026). As part of that evaluation, PJM is assessing the usefulness of a Large Load Registry to support such efforts.

¹³ Proposed RAA, Definitions – Large Load (“‘Large Load’ shall mean end-use customer(s) load that has a cumulative peak load of 50 megawatts [(“MW”)] or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site as further described in the PJM Manuals.”).

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increases, consistent with the Statement of Principles Regarding PJM issued on January 16, 2026, by the National Energy Dominance Council (“NEDC”) and the 13 governors of the PJM states, and the Ratepayer Protection Pledge introduced in March 2026,¹⁴ and as recently expanded in July 2026.¹⁵

The IRAS and the related revisions proposed herein support system reliability in the PJM Region. Insufficient commitments of capacity in the 2027/2028 and 2028/2029 Reliability Pricing Model (“RPM”) Auctions, primarily driven by the unprecedented addition of large loads, most notably data centers, have given rise to resource adequacy shortfalls—and associated real-time operational issues that IRAS is intended to address. More specifically, in Delivery Years when RPM Auctions have failed to secure sufficient capacity, under the proposed IRAS framework, PJM will have the ability to manage real-time operational issues resulting from such shortages through Interim Resource Adequacy Service Action.

Pursuant to IRAS, each Electric Distributor zone/area may be directed by PJM dispatchers to reduce load up to the MW quantity of capacity attributable to Eligible New Large Loads in that zone/area. Each Electric Distributor zone/area, in turn—based upon appropriate, documented state-sanctioned load reduction plans that are either already in place or will be developed and refined in conjunction—will determine which load to reduce in response to a PJM IRAS directive.

¹⁴ See generally Ratepayer Protection Pledge.

¹⁵ See generally Ratepayer Protection Pledge Announcement.

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Such actions by PJM at the regional level and Electrical Distributors at the local level will be informed and supported by the Large Load Registry established through this proposal. Indeed, the proposed registry will give Electric Distributors and state entities access to critical information they may elect to rely upon when fashioning such load reduction protocols (including through recently-announced VA SCC and DCC state-led workshops). By way of example, IRAS would facilitate a decision by an Electric Distributor in conjunction with relevant state entities, as applicable, to decide that specific Eligible New Large Loads may be reduced during a Delivery Year when IRAS applies, because such loads are not arranged with sufficient new capacity. Such new capacity would have either been brought by the New Large Load themselves (“Bring Your Own New Capacity” or “BYONC”) or Allocated RBP Unforced Capacity (“UCAP”) MW. This aspect of the IRAS framework is consistent with the Ratepayer Protection Pledge introduced in March 2026¹⁶ and recently expanded in July 2026,¹⁷ which recognizes that New Large Loads “will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments wherever they build data centers.”¹⁸ The availability to PJM of IRAS provides PJM with a new critical operational tool in those hours when PJM is projecting its inability to maintain reliability for the region based on system conditions.

While the enclosed Tariff revisions make clear that IRAS will be available starting with the 2027/2028 Delivery Year, i.e., June 1, 2027, PJM requests that the Commission

¹⁶ See generally Ratepayer Protection Pledge.

¹⁷ See generally Ratepayer Protection Pledge Announcement.

¹⁸ Ratepayer Protection Pledge.

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accept the enclosed proposed Tariff and RAA revisions effective October 12, 2026, which is 60 days from the date of filing. First, the requested effective date will allow PJM to start building the Large Load Registry and begin accepting information about New Large Loads and arrangements with BYONC in time to expeditiously develop and post a new VRR Curve with the New Load Loads removed to the extent they do not have arrangements with BYONC (which is another aspect of this submission).

Second, Commission action by such date, with the requested effective date, will provide regulatory certainty to parties seeking to enter into bilateral agreements for new capacity and will support the ongoing efforts of the states to establish state-level tariffs to address reduction priorities, as needed. PJM heard from data center representatives and others on this need for clarity of the IRAS rules as a condition precedent to their finalizing contracts for BYONC generation to offset their New Large Load additions. Approval of the proposed IRAS framework will provide regulatory certainty to parties seeking to enter into bilateral arrangements for new capacity, including through the ongoing, PJM-administered bilateral matching process aimed at bringing new capacity to PJM.

Third, in its recent RBP Proposal Filing,¹⁹ PJM committed, subject to Commission approval, to conduct the RBP as soon as practicable, with a target start of September 30, 2026, in accordance with the Statement of Principles Regarding PJM by the NEDC and the 13 governors of the PJM states.²⁰ A zone/area in which New Large Loads have brought

¹⁹ *PJM Interconnection, L.L.C.*, Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming from Large Loads of PJM Interconnection, L.L.C., Docket No. ER26-3380-000 (July 31, 2026) (“RBP Proposal Filing”).

²⁰ *Statement of Principles Regarding PJM*, National Energy Dominance Council, 1 (Jan. 16, 2026), <https://www.energy.gov/documents/statement-principles-regarding-pjm> [<https://perma.cc/35HJ-W56E>] (“NEDC/PJM Governors’ Principles”). The 13 state signatories are the governors of Delaware, Illinois,

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their own new capacity or have had capacity allocated to it through the RBP will be at lower risk of load reduction through the IRAS structure.

Fourth, approval of IRAS will support ongoing state efforts to establish retail-level, operational procedures through which New Large Loads that have not brought their own new capacity may be reduced ahead of residential and traditional industrial customers.

Each element of this proposal is just and reasonable. Nevertheless, in the event the Commission deems it necessary, and to help facilitate the Commission's acceptance of this filing without delay, PJM provides notice that it consents to the Commission's exercise of authority to modify and/or sever any element of the proposed Tariff and RAA language to the extent necessary and permitted under FPA section 205 and *NRG Power Marketing, LLC v. FERC*,²¹ where such modification and/or severance is consistent with PJM's overarching objectives in this filing. While the each of the reforms proposed in this filing is just and reasonable and act together to advance important resource adequacy objectives, they may also be considered discretely.

While consenting to each issue being severable, PJM notes that some elements build on each other, and therefore, Commission modification/severance of an issue may require a corresponding/conforming modification to another element in order for the

Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Except for in reference to the "NEDC/PJM Governors' Principles," reference herein to the PJM states shall include the 13 state signatories and the District of Columbia.

²¹ *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017). As the Commission has repeatedly stated, "[t]he United States Court of Appeals for the District of Columbia Circuit has held that, in certain circumstances, the Commission has 'authority to propose modifications to a utility's [FPA section 205] proposal if the utility consents to the modifications.'" *N.Y. Indep. Sys. Operator, Inc.*, 188 FERC ¶ 61,051, at P 22 n.36 (2024) (second alteration in original) (citing *NRG Power Mktg.*, 862 F.3d at 114-15); see *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141, at P 26 n.29 (2022) (same), *order on reh'g*, 182 FERC ¶ 61,096 (2023); *ISO New Eng. Inc.*, 175 FERC ¶ 61,172, at P 16 n.20 (2021) (same).

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overall framework to function. For example, PJM's proposal to shift the VRR Curve based on the amount of New Large Load with capacity coverage is dependent on the BYONC rules being in place. However, the Large Load Registry, the general obligation that Load Serving Entities bring new capacity in an amount that equals or exceeds its New Large Loads' peak load, and other elements are discrete and may be severed and addressed through separate procedures without interlocking concerns.²² For example, the proposed requirement that LSEs designate new capacity in a cumulative amount that equals or exceeds its New Large Loads' peak load or be subject to interim and conditional transmission service in emergency conditions has already been accepted in other regions and should be accepted here.²³

Further, PJM has been and continues to be in an ongoing dialogue with states and other stakeholders regarding the important issues addressed by this filing, including the interaction of federal/state responsibilities. PJM may, at the behest of the states, host workshops and other fora to advance these discussions. PJM may, pursuant to FPA section 205, amend aspects of the proposals submitted herein based on the product of those discussions, and request that the Commission afford additional time for comments and consideration as may be necessary or appropriate.

As further discussed below in Part IV, to the extent the Commission exercises such authority to modify the proposed Tariff or RAA language herein pursuant to the FPA and

²² For example, given that IRAS will not be available until June 1, 2027, the compensation program, among other proposed rules, may be resolved later without affecting the overall efficacy of this filing.

²³ See, e.g., *Sw. Power Pool, Inc.*, 195 FERC ¶ 61,213 (2026); *Sw. Power Pool, Inc.*, 195 FERC ¶ 61,196 (2026); *Sw. Power Pool, Inc.*, 194 FERC ¶ 61,031 (2026).

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NRG Power Marketing, PJM respectfully requests that the Commission expressly prescribe specific revised language to provide the “necessary predictability” for PJM to implement such change(s) even before issuance of an order on compliance.²⁴ PJM’s submittal of any compliance filing implementing such modifications would further constitute PJM’s consent and acceptance of the Commission’s modifications. PJM has the authority to consent to modifications to PJM’s proposal by the Commission, pursuant to the FPA and *NRG Power Marketing*. In contrast to the underlying facts in *NRG Power Marketing*, the proposal submitted in this filing was authorized by the PJM Board of Managers (“PJM Board”) and was not the result of a stakeholder-endorsed proposal.²⁵

At bottom, IRAS is a just and reasonable means of addressing the influx of New Large Loads into the PJM Region while maintaining resource adequacy, reliability, and affordability in a manner that respects the divide between state and federal authorities and avoids disrupting existing commercial arrangements. As the PJM Board recognized in a

²⁴ *PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,137, at P 110 (2021) (first quoting *Aera Energy LLC v. FERC*, 789 F.3d 184, 190-92 (D.C. Cir. 2015) (“[A]ffirming the Commission, finding ‘FERC’s conditional acceptance . . . simply required Kern River to substitute one number for another when allocating costs to the rolled-in shippers. . . . Because this mechanical change gave Kern River no discretion to adjust its rate models, FERC provided sufficient notice to ratepayers.’”); and then quoting *Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985) (“[V]acating when the ‘effective date of an order set[] forth no more than the basic principles pursuant to which the new rates are to be calculated.’” (second alteration in original))). As the Commission elaborated further in *PJM Interconnection*, mere “direction” without “sufficient detail on each element [of the replacement rate] that [customers/market participants] could determine when their transactions would be subject to [the new rule],” would mean that implementation of the compliance directive prior Commission approval would violate the filed rate doctrine. *Id.* (quoting *Elec. Dist. No. 1*, 774 F.2d at 493 (“[P]urchasers of electricity cannot plan their activities unless they know the cost of what they are receiving, ‘providing the necessary predictability is the whole purpose of the well-established filed rate doctrine.’” (citing *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 (1981)))).

²⁵ *NRG Power Mktg.*, 862 F.3d at 112 (noting that PJM developed proposed revisions filed with the Commission through its stakeholder process and that the proposed revisions “received overwhelming support from PJM’s stakeholders”).

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January 16, 2026 letter,²⁶ IRAS—which, in its earlier iteration, was referred to as “Connect & Manage”—is just one part of a multi-pronged, ongoing effort by PJM to respond to the challenges stemming from the influx of Large Loads into the PJM Region.²⁷ Indeed, PJM continues to make progress on a broader, holistic review of its capacity market, the RPM, to identify durable, more holistic solutions to concerns stemming from large load additions.²⁸ More specifically, on May 6, 2026, PJM issued a white paper, *Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment to Support Durable Reliability*, which *inter alia*, posed foundational questions facing PJM’s capacity market today and proffered three distinct, albeit not mutually exclusive, paths forward.²⁹ These foundational questions and proposed paths forward are a starting point towards more holistic solutions to PJM’s resource adequacy concerns.³⁰ This ongoing review is in line with the NEDC/PJM Governors’ Principles, which urged PJM to “embark on a stakeholder process to reform the capacity

²⁶ Letter of David E. Mills, PJM Board Chair, *Board Decisional Letter on Critical Issue Fast Path - Large Load Additions*, PJM Board (Jan. 16, 2026), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf> [<https://perma.cc/P57T-ZXYJ>] (“January 2026 Board Letter”).

²⁷ PJM is proposing Interim Resource Adequacy Service, as opposed to Connect & Manage,” to reflect that the proposal is for a new load reduction service provided by New Large Load that does not bring sufficient new capacity to meet the loads’ resource adequacy needs, and to avoid confusion and conflation between “Connect & Manage” and the ongoing efforts to interconnect Large Loads in the Commission’s show cause proceeding in Docket No. EL26-67 and PJM’s development (and future filing of) of an FPA section 205 proposal to address the Commission-identified issues.

²⁸ See *Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment to Support Durable Reliability* (May 6, 2026), <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2026/20260506-powering-reliability-through-market-design.pdf> [<https://perma.cc/3W8Z-M4TQ>].

²⁹ *Id.*

³⁰ PJM Interconnection, L.L.C., *PJM to Lead Market Reform Effort to Support Generation Investment and Reliability*, PJM Inside Lines (May 6, 2026), <https://insidelines.pjm.com/pjm-to-lead-market-reform-effort-to-support-generation-investment-and-reliability/> [<https://perma.cc/J2KW-LRW2>].

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market to ensure long-term viability and prevent consumers from bearing excessive ongoing costs,” with an ultimate goal of returning PJM to market fundamentals.³¹

I. BACKGROUND

PJM hosts the largest concentration of data center load in the world.³² “PJM’s load forecast predicts peak load growth of 32 gigawatts [(“GW”)] from 2024 to 2030, 30 GW of which is projected to be from data centers.”³³ Year-over-year, the shortfall of capacity supply needed to meet demand (plus a reasonable reserve margin) has *grown* despite a net increase of 1,294.4 MW Installed Capacity (“ICAP”) of supply between the 2027/2028 and 2028/2029 Base Residual Auction (“BRA”).³⁴ In other words, the addition of new supply has not kept pace with rapid large load demand growth, thus giving rise to the significant tightening of the capacity market in recent years and subsequent resource adequacy shortfalls. To mitigate the potential reliability risks associated with resource adequacy

³¹ NEDC/PJM Governors’ Principles at 1; *see also* PJM Interconnection, L.L.C., *CIFP Reliability Backstop Procurement – PJM Proposal*, 1 (June 11, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260611/20260611-item-04a---pjm-reliability-backstop-proposal---post-meeting-materials.pdf> [<https://perma.cc/X7T7-5RPB>] (providing background on stakeholder engagement).

³² *See, e.g.*, Laila Kearney, *Biggest US power grid operator moving forward with plan to manage data centers*, Reuters (Nov. 20, 2025), <https://www.reuters.com/business/energy/biggest-us-power-grid-operator-moving-forward-with-plan-manage-data-centers-2025-11-19/> [<https://perma.cc/7M34-52V4>].

³³ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 8 & n.24 (citing Letter of David E. Mills, PJM Board Chair, *PJM Board Letter Implementing CIFP for Large Load Additions*, (Aug. 8, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf> [<https://perma.cc/F9KV-B7HK>] (“August 2025 Board Letter”)). Since the issuance of the August 2025 Board Letter, PJM has published its 2026 Long-Term Load Forecast Report, which anticipates lower peak demand in the near term due to forecasting improvements, revising the peak load forecast for 2030 downward by 875 MW, but confirms significant growth in the next 20 years. PJM Interconnection, L.L.C., *PJM’s Updated 20-Year Forecast Continues to See Significant Long-Term Load Growth*, PJM Inside Lines (Jan. 14, 2026), <https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/> [<https://perma.cc/W3UY-F9HE>].

³⁴ *2028/2029 Base Residual Auction Report*, PJM Interconnection, L.L.C., 8 (July 14, 2026), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf> [<https://perma.cc/A53K-TXXY>] (“2028/2029 BRA Report”).

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shortfalls, PJM is proposing the IRAS as a mechanism to support reliability while allowing New Large Loads to connect even when new capacity supply lags behind load growth.

The 2028/2029 BRA Report, dated July 14, 2026, indicates PJM's BRA cleared short of the PJM Region Reliability Requirement³⁵ for a second consecutive year.³⁶ Specifically, PJM's BRA for the 2028/2029 Delivery Year, which ran from June 30, 2026, to July 7, 2026, cleared 6,831.3 MW (in UCAP) short of PJM's Regional Transmission Organization ("RTO")-wide reliability requirement at the market price cap of \$325/MW-day.³⁷

Last year, PJM's BRA for the 2027/2028 Delivery Year, which ran from December 4, 2025, through December, 10, 2025, likewise cleared 6,623 MW short of the PJM Region Reliability Requirement, at the market price cap of \$333.44/MW-day (UCAP).³⁸ As both the Commission and the Department of Energy ("DOE") have recently highlighted, the pace of "growth [in electricity demand] is now higher than at any point in the past two decades, driven in part by increasing quantities of large commercial and industrial load, most notably data centers, connecting rapidly to the transmission system."³⁹

³⁵ Tariff, Part I, section 1, Definitions – O – P – Q – PJM Region Reliability Requirement ("PJM Region Reliability Requirement' shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of [Fixed Resource Requirement ("FRR")] Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.").

³⁶ 2028/2029 BRA Report at 3.

³⁷ 2028/2029 BRA Report at 3.

³⁸ *PJM Auction Procures 134,479 MW of Generation Resources*, PJM Interconnection, L.L.C., 1 (Dec. 17, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20251217-pjm-auction-procures-134479-mw-of-generation-resources.pdf> [<https://perma.cc/A89W-W99B>].

³⁹ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 6 & n.18 (citing *Interconnection of Large Loads to the Interstate Transmission System*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000,

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A. *The Senior Task Force and Critical Issue Fast Path Stakeholder Processes*

On January 16, 2026, the PJM Board issued a letter announcing its decision on the CIFP process addressing large load issues in PJM, which set forth the roadmap for a multi-pronged approach to addressing resource adequacy challenges, including “accelerat[ing] and execute[ing]” a backstop capacity procurement and “address[ing] cost allocation for any such procurement, including consideration of mechanisms that assign costs to those LSEs that are short as a result of incremental load growth within their service areas.”⁴⁰ The NEDC/PJM Governors’ Principles were issued on the same day.

On March 25, 2026, the PJM Board issued a Problem/Opportunity Statement directing that PJM implement a “framework that allows qualifying large loads to connect to the PJM system subject to defined operational controls, including curtailment during specified system conditions to protect residential customers from potential power outages.”⁴¹ Subsequently, the Connect and Manage Senior Task Force (“Senior Task Force”) was established to address such a framework. The Senior Task Force met five times between March and May 2026.

at 2 (Oct. 23, 2025) (“DOE ANOPR”) (citing *2024 Long- Term Reliability Assessment*, North American Electric Reliability Corporation, 8 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf [<https://perma.cc/Z4D4-AMQT>])).

⁴⁰ January 2026 Board Letter at 6.

⁴¹ *Problem/Opportunity Statement: Board Directed ‘Connect and Manage’*, PJM Interconnection, L.L.C. (Mar. 25, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2026/20260325/20260325-item-01---2-connect-and-manage---problem-statement.pdf> [<https://perma.cc/45CR-8Z4S>].

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During that period, on April 8, 2026, the PJM Board issued a letter initiating the CIFP to engage stakeholders in the development of an RBP proposal (“RBP CIFP”).⁴² Subsequently, on May 19, 2026, the PJM Board issued a second related letter, directing that the scope of the RBP CIFP be expanded to incorporate a separate stakeholder process to identify and reduce large load in the PJM Region, when necessary, to maintain sufficient reserves to meet applicable Reserve Requirements and IROLs within limits, and avoid cascading outages, if available economic generation is not sufficient. The PJM Board determined that it would be appropriate to address both the RBP and IRAS in a single CIFP process in light of the substantive link between these two proposals.

The expanded scope RBP and IRAS CIFP concluded on June 30, 2026, following eight days of stakeholder meetings over the course of three months. On June 30, 2026, stakeholders submitted advisory votes on 11 different proposals. All 11 proposals regarding the concepts addressed by IRAS failed to achieve two-thirds stakeholder support.⁴³

B. PJM Board Determination

The PJM Board reviewed the results of the June 30, 2026 stakeholder advisory votes.⁴⁴ Ultimately, the PJM Board concluded that “[i]n light of the deteriorating resource

⁴² *Letter of David E. Mills, Interim President and CEO*, PJM Interconnection, L.L.C. (Apr. 8, 2026), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260408-cifp-rbp-initiation-letter.pdf> [<https://perma.cc/8LM5-9VX3>] (stating the intent of the letter was to address the initiation of the CIFP – RBP accelerated stakeholder process by the PJM Board).

⁴³ PJM Members Committee, *MC Voting Results for RBP Proposals Agenda Items 3L through 3X*, PJM Interconnection, L.L.C., <https://www.pjm.com/committees-and-groups/committees/mc> [<https://perma.cc/5CSQ-DP4K>] (last visited Aug. 12, 2026) (Scroll to “Meeting Materials” and search for 2026, click on link for “6.30.2026 Special MC,” scroll to MC Voting Results – Agenda Items 3L to 3X and click on each to view the PDF).

⁴⁴ As PJM reported in a recent July 20, 2026 informational filing to the Commission, PJM sought additional feedback on the RBP proposal from stakeholders on specific topics through further polling, which concluded

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adequacy outlook, and consistent with [the PJM Board] letter issued to the stakeholders on May 19, 2026, . . . PJM must take timely action within its control to begin restoring resource adequacy.”⁴⁵ Thus, the PJM Board directed PJM to file a proposal that includes the following elements:

- IRAS, which will be applicable to “[N]ew Large Loads that, as of June 1, 2027, do not bring sufficient capacity to serve their resource adequacy needs and cannot otherwise be served at the 1-in-10 reliability standard[,]” with load reductions under the service occurring before deployment of Pre-Emergency Load Management;⁴⁶
- A Large Load Registry, which will require Electric Distributors “to provide the information necessary for PJM to improve the accuracy and transparency of load forecasts and to administer the [RBP] and [IRAS];”⁴⁷
- Compensation for reduced load under IRAS “for Large Load customers that are directed to reduce their consumption” with “[d]eterminations as to which retail customers may fund such a program or whether specific Large Loads would be entitled to such compensation (or may waive such compensation consistent with the Ratepayer Protection Pledge) will be determined by state authorities under state law or [Relevant Electric Retail Regulatory Authorities (“RERRA”)] as may be applicable[,]” and administered by the relevant “Electric Distributor in coordination with the relevant state authorities or RERRA[.]”⁴⁸ and

on July 10, 2026. *PJM Interconnection, L.L.C.*, PJM Informational Report on Stakeholder Processes Addressing Resource Adequacy for Large Loads, Docket No. EL26-67-000, at 4 (July 20, 2026) (citing PJM Interconnection, L.L.C., *CIFP – Reliability Backstop Procurement / Connect & Manage, Summarized Poll Results* (2026), <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/postings/cifp-poll-results-with-comments.pdf> [<https://perma.cc/T2X8-NKGD>] (“CIFP - RBP/Connect & Manage Poll Results”)).

⁴⁵ Letter from Paula Conboy, Chair, PJM Board of Managers, *Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage*, 1 (July 27, 2026), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-board-decisional-letter-on-cifp-reliability-backstop-procurement-and-connect-and-manage.pdf> [<https://perma.cc/V9Z7-83AH>] (“PJM Board July 2026 Decisional Letter”).

⁴⁶ PJM Board July 2026 Decisional Letter at 2 (emphasis omitted).

⁴⁷ PJM Board July 2026 Decisional Letter at 1.

⁴⁸ PJM Board July 2026 Decisional Letter at 2.

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- Exclusion of “[i]ncremental [N]ew Large Loads relative to the forecast utilized for the 2028/2029 BRA . . . from the forecast used in future RPM auctions for the 2029/2030 Delivery Year and beyond unless and until there are new supply resources offered into an RPM auction in sufficient quantity to cover the [individual] [N]ew Large Load.”⁴⁹

On July 27, 2026, following a period of intense deliberation, during which the PJM Board considered the merits of the 11 proposals, as well as various letters to the PJM Board, the PJM Board issued a decisional letter directing PJM to submit the IRAS and the other enclosed revisions, and to also submit the RBP proposal set forth in this filing.⁵⁰ In a separate FPA section 205 filing on July 31, 2026, PJM submitted the RBP Proposal Filing.⁵¹ The proposal in this FPA section 205 filing reflects the IRAS framework, including the Large Load Registry and compensation for reduced load under IRAS, which was ultimately approved by the PJM Board on July 27, 2026.

C. *Related PJM Large Load Filings*

The Interim Resource Adequacy Service proposal is just one of numerous filings that PJM has submitted or will shortly be submitting to the Commission, pursuant to FPA section 205, to address the region’s resource adequacy issues.

As of today’s filing, the following matters have already been filed with the Commission:

- An RBP proposal to establish a one-time procurement of new capacity to procure for an RBP target based on the observed capacity shortfall in the 2028/2029 Delivery Year BRA, as adjusted to reflect qualifying new

⁴⁹ *CIFP Framework for Service During Periods of Insufficient Resource Adequacy – PJM Proposal*, PJM Interconnection, L.L.C., 5 (July 27, 2026), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-cifp-framework-for-service-during-periods-of-insufficient-resource-adequacy-executive-summary.pdf> [<https://perma.cc/GX7A-W3Q6>] (“CIFP Framework for Service”).

⁵⁰ See generally PJM Board July 2026 Decisional Letter.

⁵¹ See generally RBP Proposal Filing.

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capacity serving new load and certain qualifying Electric Distributors that elect and meet requirements to opt-out of the RBP;⁵²

- An Expedited Interconnection Track temporary pathway for advanced projects of significant size interconnected more quickly to address PJM's urgent need for additional Capacity Resources by facilitating the interconnection of those new generation resources—outside of PJM's Cycle Process—that commit to firm commercial-in-service dates and have a commitment from the Primary Siting Authority (or a state executive officer in certain circumstances) to expedite consideration of applicable siting, which was accepted by the Commission on June 9, 2026;⁵³
- An extension of a price collar on RPM Auction outcomes through the 2029/2030 Delivery Year, which was accepted by the Commission on April 8, 2026;⁵⁴
- A one-time, reliability-based expansion, known as the Reliability Resource Initiative, of the eligibility criteria for PJM's Transition Cycle #2 of PJM's existing interconnection queue, which the Commission accepted⁵⁵ and resulted in PJM selecting 51 projects that can come online quickly and provide more than 9,300 MW of reliable capacity;⁵⁶
- An extension of the capacity must-offer requirement to *all* available Existing Capacity Resources so as to allow RPM Auction outcomes to more accurately reflect the actual quantity of Existing Generation Capacity Resources, while continuing to safeguard against the potential exercise of market power that may be exerted by the withholding of such resources, which was accepted by the Commission;⁵⁷ and
- A compliance filing and illustrative Tariff revisions to provide that the Eligible Customer taking transmission service on behalf of a co-located load may take a transmission service that reflects the co-located load's

⁵² Since this spring, PJM has been concurrently facilitating a bilateral matching process to encourage voluntary, bilateral agreements between supply and demand for new capacity.

⁵³ See *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,197, at PP 1, 7, 44-45 (2026).

⁵⁴ See *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,076, at P 51 (2026).

⁵⁵ See *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, *reh'g denied*, 192 FERC ¶ 61,085 (2025).

⁵⁶ See *PJM Interconnection, L.L.C., PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), <https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/> [https://perma.cc/4BBH-YR3F].

⁵⁷ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,117, *order on reh'g*, 191 FERC ¶ 61,221 (2025).

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ability and willingness to limit its use of the transmission system, which, if utilized, would reduce the amount of capacity required to meet the region's resource adequacy needs. The Commission ruled on PJM's Tariff revisions and directed a future compliance filing to implement these new transmission services that PJM will soon submit.⁵⁸

The following filings aimed at addressing the impacts of new large loads on the PJM Region are forthcoming:

- A fulsome FPA section 205 filing addressing the issues the Commission raised in its June 2026 Order to Show Cause that will set forth the non-rate terms and conditions for Eligible Customers to take transmission service on behalf of large loads that are willing and able to limit their energy withdrawals from the transmission system, which, if utilized, will reduce the amount of capacity required to meet the region's resource adequacy needs; and
- Future enhancements to reserve products and updated reserve demand curves to better account for ramping and uncertainty and better align reserve pricing with operational practice.⁵⁹
- In addition, PJM has undertaken the following initiatives:
 - Improved load forecasts that include state review of large load additions, addressing duplicative requests, the use of additional third-party review and increased transparency;⁶⁰ and
 - Facilitating bilateral contracting by providing a voluntary matching service that helps connect potential buyers with sellers of capacity, as described at length in the RBP proposal filed July 31, 2026.

⁵⁸ See *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,209 (2026). On July 28, 2026, PJM submitted a motion to extend its compliance filing with respect to, among other things, the Tariff revisions implementing these new transmission services to allow for the concurrent development of the compliance language with the development of a new FPA section 205 filing to propose new transmission services for Eligible Customers taking transmission services on behalf of large loads that are not part of a co-location arrangement. *PJM Interconnection, L.L.C.*, Motion for Extension of Time for Specified Compliance Requirements and Request for Expedited Treatment of PJM Interconnection, L.L.C., Docket Nos. EL25-49-000, et al. (July 28, 2026).

⁵⁹ See *PJM Interconnection, L.L.C.*, Informational Report on Stakeholder Process Addressing Resource Adequacy for New Large Loads of PJM Interconnection, L.L.C., Docket No. EL26-67-000, at 8 (July 20, 2026).

⁶⁰ See January 2026 Board Letter at 2.

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II. THE PROPOSED REFORMS TO THE TARIFF AND THE RAA ARE JUST AND REASONABLE AND NOT UNDULY DISCRIMINATORY OR PREFERENTIAL

A. *Overview of Interim Resource Adequacy Service Framework and Responsibilities of PJM and Electric Distributors to Implement IRAS*

1. *The Interim Resource Adequacy Service framework*

As of right now, PJM will enter the 2027/2028 Delivery Year short of sufficient capacity to meet the PJM Region Reliability Requirement. As PJM has explained, this shortfall is due to a confluence of various factors, particularly the “unprecedented surge in data center load” at a faster pace than new supply can come online,⁶¹ and the “speed of connecting these large loads creates a fundamental misalignment between demand and supply cycles,”⁶² resulting in “resource adequacy in the PJM service area [being] under significant stress.”⁶³ Through this FPA section 205 filing, PJM seeks to build on its prior efforts to ameliorate the resource adequacy stress. PJM’s proposal in this filing can be broadly thought of as consisting of five parts.

One, PJM proposes to clarify an LSE’s obligation to bring new capacity in an amount that equals or exceeds its New Large Loads’ peak load or be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response. In codifying this principle, which is similar to one already inherent in SPP’s

⁶¹ See 2027/2028 Base Residual Auction Reserve Target Shortfall Report, PJM Interconnection, L.L.C., 1 (Feb. 9, 2026), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-reserve-target-shortfall-report.pdf> [<https://perma.cc/TA3Y-95AX>] (“2027/2028 BRA Report”).

⁶² 2027/2028 BRA Report at 4.

⁶³ 2027/2028 BRA Report at 2.

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large load integration construct,⁶⁴ PJM is incentivizing resource adequacy and investing in generation and related infrastructure to meet the projected demand growth.

Two, PJM proposes to administer and maintain a new Large Load Registry. Through this centralized registry, PJM will be able to gain a better understanding of all the Large Loads currently on its system and the New Large Loads that will interconnect in the future. The registry will enable PJM to better forecast load growth, plan and manage the transmission system, and study and provide the anticipated new transmission services for co-located loads and Large Loads. PJM will not be the only beneficiary of the registry, as the proposed RAA language explicitly contemplates that the registry will be available to states, Transmission Owners, Electric Distributors, LSEs, the Independent Market Monitor for PJM, and the Commission, subject to appropriate confidentiality and data protection safeguards.

Three, PJM is proposing Interim Resource Adequacy Service, a new supplemental capacity product through which New Large Loads provide a load reduction service that is a tool available to PJM to manage resource adequacy shortfalls that would otherwise drive shedding of native loads. Interim Resource Adequacy Service Action will be issued prior to calling on Pre-Emergency Load Management, placing IRAS appropriately at the beginning of PJM's actions in the event of NERC Energy Emergency Alert Level 1 ("EEA1"), and PJM will update the Emergency Procedures in its PJM Manuals to detail how and when it may call on IRAS.

⁶⁴ See, e.g., *Sw. Power Pool*, 195 FERC ¶ 61,213, concur op. (Commissioner Rosner) at P 13; *Sw. Power Pool*, 195 FERC ¶ 61,196 at P 15; *Sw. Power Pool*, 194 FERC ¶ 61,031, concur op. (Commissioner Rosner) at P 1.

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Four, PJM is proposing Bring Your Own New Capacity or “BYONC” as the category of new capacity eligible to address New Large Load capacity needs and through which a New Large Load can reduce the amount of Interim Resource Adequacy Service it may be asked to provide, consistent with the Electric Distributor’s approved load reduction rules. The amount of IRAS a New Large Load will be eligible to make available is inversely proportional to the amount of new capacity the New Large Load has brought to the PJM system. New Large Loads have a number of “self-sufficiency” avenues (in the language of the Ratepayer Protection Pledge) to avoid facing potential load reduction under state curtailment priorities implementing IRAS at the retail level. Specifically, to the extent a New Large Load does not want to provide IRAS, it needs to contract with new capacity that meets the BYONC gating criteria, which are designed to ensure the capacity is actually new and not repackaged and will provide capacity over at least 10 years. Many New Large Loads have already committed through their recently executed Ratepayer Protection Pledge to fund the electricity generation and infrastructure their projects require. IRAS provides a tool available to PJM to manage resource adequacy issues through calling for load reductions from those New Large Loads that do not adhere to the Ratepayer Protection Pledge or have otherwise not brought new eligible capacity to offset their load additions.

Five, in future RPM Auctions, PJM is proposing to exclude from the VRR Curve New Large Loads, to the extent they do not have arrangements with sufficient BYONC, beginning with the 2029/2030 Delivery Year. To the extent New Large Loads do not procure BYONC to meet their capacity needs, the rest of PJM’s load should not be exposed to the price impacts caused by those New Large Loads’ procurement of their capacity needs through the RPM Auctions. PJM’s proposal is designed to protect residential customers

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from capacity price increases resulting from the effects of New Large Loads and is therefore consistent with the Statement of Principles Regarding PJM issued on January 16, 2026, by the NEDC and the 13 governors of the PJM states and the Ratepayer Protection Pledge.⁶⁵

As discussed below, to implement these concepts, PJM proposes to establish a new Attachment DD-4 to its Tariff to house the rules for Interim Resource Adequacy Service;⁶⁶ revisions to the RAA to establish the Large Load Registry and the resource adequacy obligations associated with interconnecting New Large Loads; and revisions to Tariff, Attachment DD to adjust the VRR Curve. While each of these provisions is detailed later in this transmittal letter, PJM takes this opportunity to describe the introductory section of proposed Tariff, Attachment DD-4. Specifically, section I provides that the rules in Attachment DD-4 are supplemented by the PJM Manuals and should be read “in conjunction with the Reliability Assurance Agreement.”⁶⁷ From there, the basic concepts are introduced:

- (1) “Interim Resource Adequacy Service is a load reduction service, effective starting with the 2027/2028 Delivery Year . . . for the purpose of supporting the

⁶⁵ PJM’s proposal in this respect is based on the forecasted resource adequacy shortfalls and uncertainty today as to how much capacity will be procured through either the RBP or future BRAs. Nothing in this proposal is intended to bind PJM or the Commission in the future if and when the supply/demand balance becomes better aligned.

⁶⁶ At proposed Tariff, Attachment DD-4, the IRAS rules fit well alongside the other resource adequacy-related rules in the Tariff: Tariff, Attachment DD provides the Reliability Pricing Model rules, Tariff, Attachment DD-1 provides a copy of the RAA rules on Demand Resource participation in RPM, Tariff, Attachment DD-2 provides the rules for Peak Shaving Adjustments, and Tariff, Attachment DD-3 is the list of state policies or programs accepted as Conditioned State Support and subject to the Minimum Offer Price Rule.

⁶⁷ Proposed Tariff, Attachment DD-4, section I.

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integration of New Large Loads to the PJM Region that are not in arrangements with new capacity additions to the PJM Region;”⁶⁸

- (2) PJM can call on IRAS load reductions prior to calling on Pre-Emergency Load Management Reductions Actions when needed to avoid a capacity shortage on a regional or sub-regional basis;⁶⁹
- (3) PJM will maintain the Large Load Registry “pursuant to the Reliability Assurance Agreement . . . [to] inform which New Large Loads are eligible to be called on to provide Interim Resource Adequacy Service;”⁷⁰ and
- (4) PJM will “coordinate with Electric Distributors, and other Members as appropriate, on the provision of Interim Resource Adequacy Service” and any resulting compensation.”⁷¹

Each of these concepts is borne out in the proposed IRAS rules described in this transmittal letter.

2. Responsibilities of PJM and Electric Distributors

Because successful implementation of Interim Resource Adequacy Service will require actions from PJM and Electric Distributors, PJM’s proposal delineates broadly the responsibilities of PJM and Electric Distributors at the outset of proposed Tariff, Attachment DD-4. Section II of proposed Tariff, Attachment DD-4 provides that PJM shall be responsible for: maintaining the Large Load Registry; identifying Eligible New Large Loads and the MW quantity of IRAS needed for each Electric Distributor zone/area for a given Delivery Year, starting with the 2027/2028 Delivery Year; and issuing an Interim Resource Adequacy Service Action based on system conditions and Eligible New

⁶⁸ Proposed Tariff, Attachment DD-4, section I(a).

⁶⁹ Proposed Tariff, Attachment DD-4, section I(b).

⁷⁰ Proposed Tariff, Attachment DD-4, section I(c).

⁷¹ Proposed Tariff, Attachment DD-4, section I(d).

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Large Load Amounts directing Electric Distributors to reduce load in accordance with such Interim Resource Adequacy Service Action.⁷²

With regard to Electric Distributors, PJM proposes that they “shall” fulfill four tasks. One, Electric Distributors must execute PJM’s load reduction directives when PJM issues an Interim Resource Adequacy Alert.⁷³ As discussed below in Part II.D.4.c, this does not mean that PJM will identify specific New Large Loads for the Electric Distributor to reduce; PJM will identify only aggregate MW values that need to be reduced, but such values will be based on the maximum IRAS value PJM determined for the Electric Distributor’s zone/area prior to the Delivery Year. The Electric Distributors, in coordination with the appropriate states and/or RERRAs, LSEs, and LSE customers will determine which loads should ultimately reduce subject to IRAS. PJM here is simply memorializing current practice under which Electric Distributors, consistent with their state programs, determine how to implement load reduction directives.

Two, Electric Distributors must coordinate with PJM on the development and maintenance of the Large Load Registry. Specifically, PJM proposes that the Electric Distributors must provide PJM with “any information or data the Electric Distributor believes appropriate to facilitate an accurate Large Load Registry, including applicable state or RERRA retail tariff or contractual obligations.”⁷⁴ This coordination is just and

⁷² Proposed Tariff, Attachment DD-4, sections II(a)-(e).

⁷³ Proposed Tariff, Attachment DD-4, section III(a). In full, this provision states: The Electric Distributor shall “execute the Office of the Interconnection’s directives to implement Interim Resource Adequacy Service Actions among the Eligible New Large Loads in the Electric Distributor’s zone/area, which is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value and is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering.” *Id.*

⁷⁴ Proposed Tariff, Attachment DD-4, section III(b).

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reasonable, as the Electric Distributor is privy to much of the information the proposed Large Load Registry seeks to maintain. As discussed below in Part II.B, the initial obligation to submit data to PJM is on the LSE serving the Large Load, but in order to increase the accuracy of the registry, PJM finds valuable—and needed—the information available to the Electric Distributors.

Three, Electric Distributors must “coordinate, as appropriate, with the relevant state(s) or RERRA(s), individual Load Serving Entities, and customers served by the Load Serving Entities in its zone/area to support transparent, effective, and orderly deployment of Interim Resource Adequacy Service.”⁷⁵ Through this coordination requirement, PJM is not dictating how or on which terms the Electric Distributor must effectuate such coordination. Rather, as with the first responsibility discussed above, PJM is memorializing existing practices. And, here, PJM is merely articulating the expectation that the Electric Distributor will be the entity to identify, consistent with applicable state programs, the load to be reduced in response to an Interim Resource Adequacy Service Action.

Finally, the Electric Distributor shall “implement compensation program consistent with Tariff, Attachment DD-4, section X.”⁷⁶ As discussed below in Part II.E, PJM is not mandating how IRAS-directed load reductions are to be compensated. PJM is proposing a just and reasonable maximum rate for such service. However, given that the Electric Distributors, in accordance with state programs, will have identified the loads to be

⁷⁵ Proposed Tariff, Attachment DD-4, section III(c).

⁷⁶ Proposed Tariff, Attachment DD-4, section III(d).

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reduced, it is the responsibility of the Electric Distributor and its applicable state regulator to determine the appropriate compensation scheme. PJM's proposal offers the Electric Distributor and their state regulator much flexibility in this regard.

B. The Large Load Registry (RAA, Schedule 11, Section B)

PJM is proposing to establish a registry of Large Loads in the PJM Region to be maintained by PJM and updated periodically, and which may be “available to Authorized Commissions, Transmission Owners, Electric Distributors, [LSEs], the Market Monitoring Unit, and [the Commission]” and other entities pursuant to the Operating Agreement, section 18.17, “subject to appropriate data protection safeguards required by Operating Agreement, section 18.17.”⁷⁷ To the extent consistent with existing confidentiality protections in PJM's Governing Agreements, PJM is also proposing that aggregated data from the Large Load Registry be posted on the PJM website.⁷⁸

The Large Load Registry will contain information about Large Loads in the PJM Region that will, *inter alia*, facilitate the transparent implementation of IRAS and assist the Commission and states in monitoring whether loads are, in fact adhering to the Ratepayer Protection Pledge commitment to “build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands” and “add[ing] more capacity that serves the broader public by increasing supply” in order to protect “Americans from higher prices.”⁷⁹ PJM will use the registry to determine the quantity of New Large

⁷⁷ Proposed RAA, Schedule 11, section B.1(d).

⁷⁸ Proposed RAA, Schedule 11, section B.1(e).

⁷⁹ Ratepayer Protection Pledge; Ratepayer Protection Pledge Announcement; *see also Fact Sheet: President Donald J. Trump Advances Energy Affordability with the Ratepayer Protection Pledge*, The White House (Mar. 4, 2026), <https://www.whitehouse.gov/fact-sheets/2026/03/fact-sheet-president-donald-j-trump->

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Loads by zone/area and allocate IRAS responsibility to each zone/area accordingly, starting with the 2027/2028 Delivery Year. States may leverage the Large Load Registry to inform the implementation of retail constructs including load reduction priorities and cost allocation at the retail level to appropriate end-use customers. The Large Load Registry will assist states in administering their respective programs at the retail level while allowing each state to retain the flexibility to administer those programs, including the flexibility to determine when and whether Large Loads and Existing Large Loads have demonstrated that their loads are matched with new capacity that they have procured to serve their needs. PJM also anticipates that the proposed Large Load Registry may also support recent efforts by NERC to “aggressively work[] toward revised registry criteria and standards”⁸⁰ in accordance with the Commission’s recent order, pursuant to section 215(d)(5) of the FPA,⁸¹ directing NERC to “develop changes to NERC’s Rules of Procedure, including registry criteria, necessary for the registration of computational load entities.”⁸²

advances-energy-affordability-with-the-ratepayer-protection-pledge/ [https://perma.cc/N366-NGF4] (listing the companies who joined the Ratepayer Protection Pledge).

⁸⁰ *Large Loads Action Plan: Understanding and addressing the reliability risks of emerging large loads*, North American Electric Reliability Corporation, <https://www.nerc.com/initiatives/large-loads-action-plan> [https://perma.cc/87WF-F4LV] (last visited Aug. 13, 2026);

⁸¹ 16 U.S.C. § 824o(d)(5).

⁸² *Reliability Standard(s) Pertaining to Computational Load Integration*, 196 FERC ¶ 61,031, at P 10 (2026). NERC has announced that it will be issuing its second draft of the registry criteria for public review on August 19, 2026. NERC, (@NERC_Official), X (Aug. 5, 2026, at 4:34 PM), https://x.com/NERC_Official/status/2085102044054953996 [https://perma.cc/4EWU-2E83].

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1. *Overwhelming support from PJM stakeholders for a New Large Load Registry to be established and maintained by PJM*

PJM's proposal to establish a Large Load Registry received overwhelming support from PJM stakeholders. Indeed, in response to a poll of stakeholders posted on July 16, 2026, 82% of the 66 stakeholder respondents agreed that a Large Load registration requirement is necessary to "ensur[e] that costs of new capacity required to serve new large load should be allocated to data centers."⁸³ Furthermore, seven of the 10 proposals put forward by PJM's stakeholders similarly include a Large Load Registry.⁸⁴ In addition, in response to the July 16, 2026 poll of stakeholders, at least seven stakeholder respondents noted that the Large Load Registry is likely to provide the necessary transparency to identify Large Loads while supporting the overall success of the IRAS framework.⁸⁵ One stakeholder respondent noted that "[a] registry provides the transparency needed to identify new large loads, their locations, and whether they have secured qualifying BYONC or other

⁸³ CIFP - RBP/Connect & Manage Poll Results at 4.

⁸⁴ See Connection and Manage Senior Task Force, *Implementation of Connect and Manage Framework for Large Load Interconnections Package/Proposal Matrix*, PJM Interconnection, L.L.C., Sheet 6 (3. Package Matrix) (June 30, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-cifp---connect-and-manage---options-and-packages-matrix.xls> [https://perma.cc/59X5-P7WG] (The following stakeholder proposals also included the concept of a Large Load Registry: (1) Joint Electric Distribution Companies (Joint EDCs); (2) Glatz-Silverman; (3) Calibrant; (4) Joint Consumer Advocates; (5) Natural Resources Defense Council (NRDC); (6) E-Cubed Policy Associates; and (7) Voltus.).

⁸⁵ CIFP - RBP/Connect & Manage Poll Results at 33 (Stakeholder respondents noted that "[a] registry is necessary for both the Reliability Backstop Procurement and for the Connect & Manage framework to ensure costs and curtailments are assigned appropriately. Consistent with the Statement of Principles, a registry will ensure that new Large Load customers (cost causers), through the LSEs that serve them, are appropriately assigned the cost of capacity procured through the Reliability Backstop Procurement (RBP) mechanism. Absent a registry, it is unclear how other end-use consumers could be insulated from these costs. . . . Additionally, it is unclear how, absent a registry, a Connect & Manage framework could be implemented in a way that protects other end-use consumers from being curtailed in response to a PJM Connect & Manage event.").

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reliability arrangements.”⁸⁶ Another noted that “[a] registry is one means of satisfy[ing] the principle of ensuring that costs of new capacity required to serve new large load (i.e., data centers) should be allocated to data centers.”⁸⁷ Overall, there was broad support across the stakeholder sectors for a registry registration requirement.⁸⁸

2. *The proposed definition of Large Load is just and reasonable*

PJM’s proposed Large Load Registry, which will provide the critical data transparency needed to establish load reduction priorities for retail customers through IRAS, begins with a definition of Large Load. PJM proposes to define Large Load as “end-use customer(s) load that has a cumulative peak load of 50 megawatts or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site as further described in the PJM Manuals.”⁸⁹

PJM’s proposed definition of Large Load is in line with the Commission’s June 2026 Order to Show Cause regarding Large Loads, wherein the Commission expressly found that “PJM’s Tariff appears to be unjust and unreasonable because it lacks a definition of large load, as a new category of load.”⁹⁰ More specifically, the Commission held that

⁸⁶ CIFP - RBP/Connect & Manage Poll Results at 32.

⁸⁷ CIFP - RBP/Connect & Manage Poll Results at 32.

⁸⁸ CIFP - RBP/Connect & Manage Poll Results at 5-6 (Of the 82% of stakeholder respondents that agreed that a large load registration requirement is necessary to ensure that costs of new capacity required to serve new load should be allocated to data centers, 18 were Electric Distributors, 16 were End-Use Customers, 6 were Generation Owners, 7 were Other Suppliers, and 7 were Transmission Owners).

⁸⁹ Proposed RAA, Definitions – Large Load.

⁹⁰ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

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“an appropriate definition, including a load size and interconnection voltage threshold, should be based on the characteristics of PJM’s transmission system.”⁹¹ The Commission thus requested that PJM “explain whether the Tariff remains just and reasonable without such a definition, or propose Tariff revisions establishing its own definition of large load.”⁹²

The Commission, in its June 2026 Order to Show Cause, preliminarily found that, based on the record in the DOE ANOPR proceeding, “it appears that it would be reasonable to define a large load as a new, commercial or industrial customer, located at a single site behind one or more points of interconnection, and that has a peak load of 50 MW or greater, interconnects to the transmission system at a voltage level of greater than 69 [kilovolts (“kV”)], and is not part of a co-location arrangement.”⁹³ However, while the Commission stated that its proposed definition “appears . . . [to] be reasonable,” the Commission furthermore acknowledged that PJM may establish “its own definition of large load.”⁹⁴

PJM proposes to define Large Load in terms that are substantially similar to the Commission’s preliminary proposal. Specifically, like the Commission’s preliminary definition, PJM is proposing that Large Load, as defined in the Tariff: (1) has a peak load of 50 MW or greater; (2) be located at a single site; and (3) be behind one or more points of interconnection. Nevertheless, PJM’s proposed definition of Large Load differs from

⁹¹ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

⁹² June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

⁹³ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

⁹⁴ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

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the Commission's in several ways to reflect the characteristics and realities of Large Loads in the PJM Region.

First, the 50 MW or greater threshold, as proposed by PJM, is a *cumulative* peak load of 50 MW. During the stakeholder process, PJM was informed that a single entity that is an end-use customer in PJM may actually consist of a number of smaller loads with a cumulative have a peak load of 50 MW or greater. Thus, to capture the smaller loads of a single entity—e.g., disparate, closely located data centers owned by a single company—and to avoid any gamesmanship from splitting up a Large Load into smaller loads, but all within the same area, PJM is proposing that the *cumulative* peak load be equal to or greater than a 50 MW threshold.

Second, Large Load is located at a single electrical site behind one or more points of interconnection *within a one-mile radius*. The one-mile radius requirement is intended to avoid a scenario where, for example, a data center owner is not categorized as Large Load simply because the owner has elected to site a number of smaller data centers, each with peak loads below 50 MW, close together.⁹⁵ The Commission has explicitly adopted a one-mile test in other situations to determine whether facilities are “at the same site” to be a Qualifying Facility. There, the Commission has set and applied an irrebuttable presumption that they are a single facility at a single site when the distance between

⁹⁵ *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (revising one-mile rule for small power production facilities seeking Qualifying Facility status as an analog), *order on reh'g & clarifying in part*, Order No. 872-A, 173 FERC ¶ 61,158 (2020).

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equipment at two facilities is one mile or less.⁹⁶ Adoption of a similar criterion for determining Large Loads is also just and reasonable.

Similarly, the reference to a single “electrical” site is similarly intended to avoid a scenario where data centers and other Large Loads avoid the 50 MW threshold by configuring themselves into smaller loads. Data centers and other Large Loads that are physically located together or act as a single facility are a single “electrical” site. In the same vein, companies may site many affiliated facilities in the same general areas but could site them in a manner that could allow the facilities to individually avoid falling within a definition of Large Load. Therefore, PJM is proposing to extrapolate in the definition that there are many different configurations that may constitute a single electrical site, particularly where there are multiple facilities that are affiliated in the same general area. These criteria are logical and helpful for purposes of defining Large Load and minimizing risks of gamesmanship.

Given the multitude of possible configurations and the other possible variations, PJM intends to detail in the PJM Manuals the method of calculating the one-mile distance and for examining different configurations to determine whether they may constitute a single electrical site. Such implementation details are needed, and explicitly called for in the proposed definition of Large Load.

Third, Large Load, as proposed by PJM, is defined as “*end-use customer(s) load*” rather than the Commission’s proposed “new, commercial or industrial customer.” PJM proposes to define Large Load to refer specifically to the MW quantity of the demand

⁹⁶ Order No. 872, 172 FERC ¶ 61,041 at PP 17, 62, 466; *see* 18 C.F.R. § 292.204(a)(2).

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created by the customer rather than the customer itself. In other words, as reflected below, during emergency conditions IRAS will not be used in real-time operations to require the reduction of specific end-use customers but, rather, will be focused on directing that a certain MW quantity be reduced by the Electric Distributor in order to maintain system reliability in the face of resource adequacy challenges. PJM is also proposing that Large Load encompass all end-use customer(s) load that meet the other requirements, thus avoiding singling out commercial or industrial customers specifically. That said, PJM does not contemplate that residential customers or smaller industrial customers would have peak loads anywhere near 50 MW, which represents, roughly, the electricity consumption of between 25,000 and 50,000 homes.⁹⁷

Fourth, PJM's proposed definition of Large Load also excludes several provisions reflected in the Commission's definition. Namely, PJM is not proposing that Large Load be limited to connecting to the system at a voltage of 69 kV or greater, is not excluding co-location arrangements from the definition, and is not limiting the definition to new load. PJM understands that other regions have identified a need for specifying a voltage criterion in a Large Load definition because "different-size loads may have different impacts on the transmission system depending on the voltage level at which they interconnect," the prevalence of 69 kV transmission lines on their system, and the existence of transmission that is less than 69 kV.⁹⁸ While PJM's transmission system has some transmission that is

⁹⁷ PJM is not using the Tariff defined term, "End-Use Customer," as not all relevant customers may necessarily fit under that term. End-Use Customer, as defined in the RAA, "shall mean a Member that is a retail end-user of electricity within the PJM Region." RAA, Article 1, Definitions (defining End-Use Customer). For purposes of this proposal, not all relevant customers of LSEs may be Members of PJM.

⁹⁸ See *Sw. Power Pool*, 194 FERC ¶ 61,031 at P 61.

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less than 69 kV in certain zones, to date, PJM's processes and stakeholder engagement have not identified any need to draw a distinction between Large Loads connecting at different voltage levels given the specific purpose of IRAS as outlined herein. As such, PJM's proposed definition does not include the Large Load connecting to the system "at a voltage level of greater than 69 kV" criterion. PJM is also not proposing that the definition of Large Load exclude load that is "part of a co-location arrangement." Rather, PJM's proposed definition of Large Load is focused on the MW quantity threshold of load located close in distance at a single electrical site. Rather than entirely excluding such load from the definition of Large Load by virtue of its co-location with generation, PJM has proposed rules that specifically address situations in which Large Load is co-located with their own generation. Also, Large Load, as defined, is not limited to "new" load. Instead, PJM is proposing a separate definition, "New Large Load," to capture the temporal aspect of such load with greater specificity. In addition, PJM is proposing to define those New Large Loads that are eligible to provide IRAS as Eligible New Large Load. The definitions of New Large Load and Eligible New Large Load are described below in Parts II.B.3.a and II.C.6, respectively.⁹⁹

3. *Information reported in the Large Load Registry*

PJM is proposing that LSEs submit information to PJM about the Large Loads they serve,¹⁰⁰ and also that PJM may obtain information, as needed, from the Electric

⁹⁹ While PJM is proposing a just and reasonable definition of Large Load, as part of the ongoing NERC and large load show cause response efforts, PJM will continue to engage with the industry and stakeholders to consider operational impacts and requirements necessary to address situations where multiple unaffiliated loads aggregate up to or in excess of 50 MW in relatively close proximity to each other.

¹⁰⁰ Proposed RAA, Schedule 11, section B.1(a).

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Distributors whose zone(s)/area(s) the LSEs are located and the Transmission Owner.¹⁰¹

Furthermore, PJM may also consult with the Large Load.¹⁰²

The Large Load Registry will contain the following information about each Large Load in the PJM Region:

- Eligible Customer/Network Customer for Large Load;
- Description of Large Load;
- Location(s) (Control Zone, Electric Distributor zone/area, where a zone/area is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering);
- In-service date for each increment of load;
- Peak shaving adjustment value pursuant to a state program codified in state law and whether and how it meets the requirements of Tariff, Attachment DD-2;
- Delivery point / Point(s) of interconnection (include all if more than one);
- Peak load quantity (MW) and ramp schedule, if applicable;
- Telemetry specifications;
- BYONC quantity (MW) and ramp schedule, if applicable;
- Allocated RBP UCAP MW quantity (MW), if applicable;
- Backup generation (MW), including fuel type and relevant permitting limitations;
- Contracts or service agreements between the Large Load and the LSE;
- Points of contact at the applicable Transmission Owner, Electric Distributor, and Load Serving Entity;
- EMS B1/B2/B3 name (for the applicable Transmission Owner, Electric Distributor); and
- Additional details and contents as necessary, in accordance with the PJM Manuals.¹⁰³

Each piece of information is a necessary component to the Large Load Registry and provides key information to PJM, as well as Authorized Commissions, Transmission

¹⁰¹ Proposed RAA, Schedule 11, section B.1(b).

¹⁰² Proposed RAA, Schedule 11, section B.1(c).

¹⁰³ Proposed RAA, Schedule 11, section B.1(a).

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Owners, Electric Distributors, LSEs, the Market Monitoring Unit, and the Commission, subject to data protection safeguards pursuant to the Operating Agreement, section 18.17, as discussed below in Part II.B.3.d. The information in the Large Load Registry will be used, as needed, for purposes that include implementation of IRAS, effective starting with the 2027/2028 Delivery Year.¹⁰⁴ Below, PJM describes how the information required to be reported in the Large Load Registry will support IRAS and allow PJM to determine the MW value of load that is required to be made available for IRAS in each Electric Distributor zone/area.

- a. Information in the Large Load Registry will help PJM distinguish Large Loads from New Large Loads and identify New Large Loads eligible for IRAS.

The information submitted to or obtained by PJM for inclusion in the registry will allow PJM to distinguish Large Loads from New Large Loads. As noted above, PJM's proposed definition of Large Loads, unlike the Commission's, does not require that the Large Load is new. Rather, PJM is proposing a separate definition of New Large Load, which will mean "an end-use customer load that is either (a) a Large Load that goes into service after June 1, 2027, or (b) incremental load in-service after June 1, 2027, that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load."¹⁰⁵

The in-service date for the Large Load, including each increment of Large Load coming online, is a critical piece of information, because only New Large Load may be

¹⁰⁴ Proposed RAA, Schedule 11, section B.3.

¹⁰⁵ Proposed Tariff, Definitions – New Large Load.

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designated “Eligible New Large Load”—i.e., New Large Load that is eligible to provide IRAS. The reason for this is straightforward. Namely, IRAS applies in Delivery Years when the amount of Capacity Resources committed falls short of the PJM Region Reliability Requirement.¹⁰⁶ As described below in Part II.C.7, such a shortfall arises when new load comes onto the PJM system without bringing their own capacity. IRAS, as proposed, is a service that specifically allows for Large Loads to interconnect without bringing their own capacity, on the condition that “they must reduce their load or switch to on-site backup resources under specific, limited” emergency conditions.¹⁰⁷ Furthermore, in recent years, the majority of the new load that has come onto the PJM system has been Large Load.¹⁰⁸ PJM is therefore limiting the MW quantity of Large Load that may be subject to reduction pursuant to IRAS to the MW value of New Large Load that has not brought their own capacity.

At the beginning of IRAS, New Large Load will be Large Load that is in-service after June 1, 2027.¹⁰⁹ In subsequent years, the relevant in-service date for a Large Load to qualify as New Large Load will fluctuate based on whether or not IRAS is needed in the manner set forth below. Thus, the in-service date will continue to be relevant to IRAS in future years. More specifically, pursuant to PJM’s proposed definition of New Large Load,

¹⁰⁶ Proposed Tariff, Attachment DD-4, sections IV(b)(i)-(ii).

¹⁰⁷ CIFP Framework for Service at 1.

¹⁰⁸ August 2025 Board Letter at 1 (“Recent increases in large load additions, mainly from data centers, present both opportunities and challenges for the regional grid. PJM’s location, size, market opportunities and system reliability make it an attractive area for large load customers to locate, and we continue to see significant load interconnection activity at several of our utilities. Indeed, PJM’s 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers.”).

¹⁰⁹ Proposed Tariff, Definitions – New Large Load.

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“to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then New Large Load shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met or (b) incremental load in-service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load.”¹¹⁰

- b. Information in the Large Load Registry will assist in identifying Eligible New Large Loads that may be called on to reduce their load or switch to on-site back-up resources pursuant to IRAS.

In a Delivery Year where IRAS applies, the MW subject to IRAS that PJM will allocate to an Electric Distributor zone/area will be limited to the MW quantity of New Large Loads in that zone/area without arrangements for BYONC or RBP UCAP MW allocated to them. PJM is therefore proposing that the Large Load Registry include information needed to distinguish between New Large Load with and without arrangements for capacity including, for example, the BYONC quantity and schedule for incremental build out of the New Large Load’s energy demands (i.e., ramp schedule), and the quantity of Allocated RBP UCAP MW associated with each Large Load. Information in the registry will assist PJM in determining the quantity of New Large Loads by zone/area that did not BYONC (or have RBP UCAP MW) and allocate an appropriate MW value of

¹¹⁰ Proposed Tariff, Definitions – New Large Load.

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IRAS responsibility to each zone/area starting with the 2027/2028 Delivery Year. Using the registry information, and subject to real-time needs of the system, New Large Loads that have not arranged for BYONC or been assigned Allocated RBP UCAP MW may, in accordance with arrangements involving the Electric Distributor and relevant state authorities, be subject to load reduction prior to the MW quantity associated with other, in-service New Large Loads that have arrangements with BYONC and/or Allocated RBP UCAP MW in the registry.

- c. Information in the Large Load Registry will assist PJM operators in determining how best to support reliability during periods of insufficient capacity.

Much of the information that PJM is proposing to require in the Large Load Registry is needed by the Electric Distributor and state authorities to make decisions that will, in turn, also inform determinations by PJM operators about how best to manage the system and avoid a Manual Load Dump Action.¹¹¹ For example, the peak load MW value associated with a Large Load in a particular Electric Distributor zone/area will help inform PJM operators of the potential capacity needs in that particular zone/area. The peak shaving adjustment value pursuant to a state program codified in state law and meeting the requirements of Tariff, Attachment DD-2 will inform PJM operators of Large Loads that are managing their resource needs through peak shaving adjustments under a state program.

¹¹¹ Systems Operations Division, *PJM Manual 13: Emergency Operations*, PJM Interconnection, L.L.C., section 2.3.2 (rev. 98, June 24, 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf> [<https://perma.cc/HE9Y-BNQK>] (“PJM Manual 13”) (defining a Manual Load Dump Action as “an Operating Instruction from PJM to shed firm load when the PJM RTO cannot provide adequate capacity to meet the PJM RTO’s load and tie schedules, or critically overloaded transmission lines or equipment cannot be relieved in any other way”).

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The locations, including the service zone/area of an Electric Distributor, of each Large Load will assist PJM operators in managing capacity needs across the PJM Region.

Furthermore, as noted above, PJM is not excluding co-located load or load with backup generation from the definitions of Large Load and New Large Load. To the extent that Large Load is co-located or has backup generation, PJM is proposing that this be identified in the Large Load Registry.

d. Confidentiality pursuant to Operating Agreement, section 18.17

PJM is proposing to maintain the confidentiality of the information in the Large Load Registry “[t]o the extent such documents, data, or other information provided to the Office of the Interconnection has been designated as confidential by a Party, Electric Distributor, or other entity supplying the information,” pursuant PJM’s existing confidentiality obligations under Operating Agreement, section 18.17.¹¹² Furthermore, subject to the appropriate data protection safeguards required by Operating Agreement, section 18.17, information maintained in the Large Load Registry may be available to Authorized Commissions, Transmission Owners, Electric Distributors, LSEs, the Market Monitoring Unit, the Commission.¹¹³

In addition, to aid transparency to the public, PJM will post aggregated data from the Large Load Registry, which will be aggregated by Electric Distributor zone/area, where possible and in a manner consistent with existing confidentiality protections. Aggregating the data by zone/area supports transparency by putting stakeholders on notice of the

¹¹² Proposed RAA, Schedule 11, section B.1(d).

¹¹³ Proposed RAA, Schedule 11, section B.1(d).

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zones/areas that have been assigned IRAS in a given Delivery Year, that may be potentially required to reduce load under certain emergency conditions pursuant to IRAS, while maintaining the confidentiality of the data.

Furthermore, PJM intends to develop provisions in its Manuals to implement the Large Load Registry, as needed, including details about who may access the information and specific safeguards in place to maintain the confidentiality of certain data. PJM intends, for example, to propose revisions to its Manuals that would permit Electric Distributors to access their specific information in the registry. PJM anticipates that each Large Load will have a specific randomized identifier in the registry, and that Electric Distributors will inform customers who have been included in the Large Load Registry and each customer's Large Load identifier. To link Large Load to a BYONC resource, a Capacity Market Seller may input the relevant BYONC resource into their account and associate it with the Large Load identifier. By relying on randomized identifiers, PJM effectively allows for some transparency while also maintaining confidentiality of Large Loads with BYONC.

- e. Reliance on Large Load Registry must reflect accurate and complete information on which PJM may determine a baseline.

PJM will review the information provided and coordinate with the applicable Transmission Owner and Electric Distributor to check the validity of the information provided, request additional information if needed, and consult with the Large Load.¹¹⁴ The information provided in the Large Load Registry will form the foundation for an

¹¹⁴ Proposed RAA, Schedule 11, section B.1(c).

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accurate, complete, and reliable database that will inform, *inter alia*, decisions about the MW quantity of New Large Loads that is available to provide IRAS in a Delivery Year.

PJM is aware that false or misleading statements about, for example, Peak Load Contributions could give rise to inaccurate baselines on which PJM would rely in the course of determining Eligible New Large Load Amounts, i.e., the MW value of load that an Eligible New Large Load in a given zone/area may be required to be made available for IRAS.¹¹⁵

The longstanding provisions against intentionally false statements or omissions of material fact extend to the reporting of information to the Large Load Registry. Specifically, pursuant to FPA section 222¹¹⁶ and 18 C.F.R. § 1c.2, “it shall be unlawful for any entity, directly or indirectly, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, . . . [t]o make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading.”¹¹⁷ Furthermore, to the extent that Electric Distributors, LSEs, and Large Loads are “Sellers,”¹¹⁸ they are required, pursuant to the Commission’s Rules and Regulations, to “provide accurate and factual

¹¹⁵ Indeed, falsifying or artificially lowering Peak Load Contributions for purposes of increasing profits for the provision of demand response has given rise to significant scrutiny by the Commission’s enforcement office. See *Lincoln Paper & Tissue, LLC*, 140 FERC ¶ 61,031 (2012); *Competitive Energy Servs. LLC*, 144 FERC ¶ 61,163 (2013).

¹¹⁶ 16 U.S.C. § 824v.

¹¹⁷ 18 C.F.R. §§ 1c.1(a), 1c.2(a); 16 U.S.C. § 824v.

¹¹⁸ A “Seller” is “any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the Federal Power Act.” 18 C.F.R. § 35.36(a)(1).

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information and not submit false or misleading information, or omit material information, in any communication with the Commission,” as well as with PJM, “unless Seller exercises due diligence to prevent such occurrences.”¹¹⁹

False or misleading statements or material omissions may give rise to a referral to the Commission’s Office of Enforcement and Regulatory Accounting. Violators, including individuals, of the duty of candor and the prohibition against false or misleading statements may be subject to significant penalties, including civil penalties of over \$1.5 million per violation per day.¹²⁰ The authority of PJM to validate the information submitted into the database and consult with the Large Load supports PJM’s efforts to make the Large Load Registry an accurate and reliable dataset. Furthermore, the underlying prohibition against false or misleading statements or material omissions provides PJM with reasonable confidence that the information provided will be a reliable basis for establishing a baseline for purposes of IRAS.

4. *PJM’s exercise of authority to require information from LSEs and Electric Distributors, and to obtain information from Large Loads and other entities*

PJM is proposing to require that the information used to develop and maintain a Large Load Registry be “submit[ted] or cause to be submitted” to PJM by LSEs, pursuant to proposed RAA, Schedule 11, section B.1(a).¹²¹ In addition, PJM proposes to obtain information from Electric Distributors,¹²² to coordinate with applicable Transmission

¹¹⁹ 18 C.F.R. § 35.41(b).

¹²⁰ *Civil Monetary Penalty Inflation Adjustments*, Order No. 906, 190 FERC ¶ 61,006 (2025).

¹²¹ Proposed RAA, Schedule 11, section B.1(a).

¹²² Proposed RAA, Schedule 11, section B.1(b).

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Owners and Electric Distributors, as needed, to validate the information provided in the Large Load Registry, and/or to consult with relevant Large Loads.¹²³

The data PJM is requesting for the Large Load Registry in this proposal builds upon PJM's existing authority and Commission precedent. Authority exists today in the Operating Agreement to require Electric Distributors to provide to PJM "all System, accounting, customer tracking, load forecasting (including all load to be served from its System) and other data necessary or appropriate to implement or administer [the Operating Agreement], and the Reliability Assurance Agreement[.]"¹²⁴ The Commission has also previously accepted proposals by PJM to require and obtain information from jurisdictional entities such as Electric Distributors and LSEs. For example, in 2024, the Commission accepted PJM's proposed revisions to the RAA to incorporate, into its forecast, Load Adjustments, which would be reported by Electric Distributors and/or their LSEs.¹²⁵

Furthermore, PJM's information-gathering authority is wide, and the Commission has permitted PJM to seek information from non-jurisdictional entities such as retail customers to the extent that the information is relevant to Commission-jurisdictional services and rates.¹²⁶ Indeed, an analogous practice can be found in longstanding

¹²³ Proposed RAA, Schedule 11, section B.1(c).

¹²⁴ Operating Agreement, section 11.3.3(h).

¹²⁵ *PJM Interconnection, L.L.C.*, 188 FERC ¶ 61,200, at P 40 & n.65 (2024) (finding that an "Electric Distributor is the party with the distribution and metering facilities defining a zone/area and responsible for reporting load information to PJM[.]" and also noting that, "under the current framework, each LSE already reports their peak load contribution to the Electric Distributor, which is the entity ultimately responsible for reporting that information to PJM." (quoting *PJM Interconnection, L.L.C.*, Response to Deficiency Letter, Request for Commission Action by September 23, 2024, Request for Waiver of the 60-Day Notice Requirement, and Request for a Shortened Seven Business Day Comment Period, Docket No. ER24-2447-001, at 9-10 (Aug. 9, 2024))).

¹²⁶ *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 278-79 (2016) ("EPISA"); FPA section 201(b), 16 U.S.C. § 824(b).

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requirements applicable to Demand Resources, as set forth in Order No. 719-A.¹²⁷ In that order, the Commission prohibited PJM and other RTOs/Independent System Operators (“ISO”) from accepting bids from Curtailment Service Providers that aggregated demand response of customers of utilities distributing below a MW per hour threshold unless otherwise permitted by an appropriate retail authority.¹²⁸ To comply with Order No. 719-A, the Commission required that PJM and other RTOs/ISOs review evidence and information concerning end-use customer participation in load response programs. In PJM’s case, PJM explained that, “when an LSE or Electric Distribution Company does not present evidence that the Retail Authority permits or conditionally permits demand response activity, the registration will not be processed until evidence of Retail Authority authorization for the resource’s participation in PJM’s load response programs is provided to PJM within the established deadlines.”¹²⁹

Furthermore, PJM’s authority to obtain “data and details concerning large load additions” finds support in the Commission’s June 2026 Order to Show Cause, which expressly required PJM and the PJM Transmission Owners to post and regularly update data and details concerning large load additions.¹³⁰

¹²⁷ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, 128 FERC ¶ 61,059, *order on clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

¹²⁸ Order No. 719-A, 128 FERC ¶ 61,059 at P 60; *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,211, at P 3 (2011).

¹²⁹ *PJM Interconnection*, 135 FERC ¶ 61,211 at P 3 (citing *PJM Interconnection, L.L.C.*, Request for Limited Tariff Waiver, and Request for Fast Track Processing of PJM Interconnection, L.L.C., Docket No. ER11-3386-000, at 4-5 (Apr. 19, 2011)).

¹³⁰ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 74.

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In fact, the Commission found, therein, that PJM's Tariff appeared to be unjust and unreasonable because it lacked, *inter alia*, "provisions that would require PJM and the Transmission Owners to publicly post and regularly update data that details: (1) the aggregate amounts of proposed large load additions in PJM's footprint, including the aggregate amounts in each transmission pricing zone."¹³¹ In particular, the Commission expressed concern that "without sufficient transparency . . . stakeholders may lack information and visibility regarding the costs driven by large load additions."¹³² Likewise, the Large Load Registry provides transparency to PJM, states, the Independent Market Monitor for PJM, and other entities with the ability to obtain such information and—through aggregated data posted on PJM's website—transparency to stakeholders, regarding the zones/areas with the greatest concentrations of Large Loads that may be eligible to provide IRAS during a particular Delivery Year. As such, PJM's proposal to gather the data, materials, and other inputs into the Large Load Registry is in line with the Commission's overall interest in supporting transparency with respect to information about Large Loads.

¹³¹ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 76.

¹³² June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 74.

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C. New Large Loads Can Avoid Being Subject to Interim Resource Adequacy Service by Bringing New Capacity to Offset Their Capacity Needs. This Is Consistent with the Ratepayer Protection Pledge and Is a Just and Reasonable Condition to Maintaining System Reliability.

1. Requirement for New Large Loads to bring capacity or be subject to load reductions

To make clear an LSE's obligations associated with bringing a New Large Load to the transmission system, PJM is proposing a new section 7.8 to the RAA. Article 7 of the RAA is for detailing LSEs Reserve Requirements and Obligations, and PJM proposes to expand those obligations, effective June 1, 2027, to include a requirement that the LSE serving each New Large Load "designate one or more Generation Capacity Resources or Capacity Storage Resources that had not cleared an RPM Auction as Network Resource(s) in a cumulative amount that equals or exceeds the LSE's New Large Load's peak load (in MW) as reported in the Large Load Registry pursuant to RAA, Schedule 11."¹³³ To the extent, the LSE does not designate a sufficient amount of Network Resources, then "such New Large Load may be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response."¹³⁴ This provision of the proposed section, while it includes the concepts that underlie the IRAS framework, is not dependent on Commission acceptance of the IRAS rules in proposed Tariff, Attachment DD-4 to be effective.

To tie this concept with the IRAS program, PJM further proposes a second sentence that joins this provision with the IRAS program. Specifically, it provides that to the extent

¹³³ Proposed RAA, section 7.8.

¹³⁴ Proposed RAA, section 7.8.

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an LSE service a New Large Load has not “designated such Network Resource(s) as BYONC with which it has entered into an arrangement in accordance with this requirement and Tariff, Attachment DD-4,” the New Large Load will need to provide IRAS “subject to the rates, terms, and conditions of Interim Resource Adequacy Service, as set forth in Tariff, Attachment DD-4.”¹³⁵ These IRAS rates, terms, and conditions are discussed in the following sections of this transmittal letter.

2. *Bring Your Own New Capacity arrangements with New Large Load*

To incentivize Large Loads to address the capacity shortfall caused by their rapid growth, in both speed to interconnection and volume of capacity needed, PJM is proposing to allow New Large Loads to remove themselves—in whole or in part—from the MW eligible for IRAS where such loads bring new capacity to the PJM Region. As discussed below, to ensure such capacity is in fact “new” and not simply existing generation capacity that is repackaged, and to ensure the benefits of the new capacity are not ephemeral and will not dissipate quickly, PJM is proposing for such new capacity certain gating criteria and imposing capacity market participation requirements.

a. PJM proposes to define BYONC as new megawatts of Unforced Capacity.

Before turning to the gating criteria and market participation requirements, it is important to understand what this new capacity is definitionally. First, PJM is calling this new capacity “Bring Your Own New Capacity,” or “BYONC” for short, to convey that the New Large Load should bear some responsibility for bringing this new capacity to correspond with the addition of the New Large Load.

¹³⁵ Proposed RAA, section 7.8.

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Second, at a basic level, BYONC is “megawatts of Unforced Capacity.”¹³⁶ This is consistent with how Capacity Resources under PJM’s capacity market design are also MW and not the underlying physical resource that supports a Capacity Resource.¹³⁷ RPM Auctions clear MW of UCAP; that is the traded product. Thus, in the same vein, BYONC is designed to offset the capacity need presented by the New Large Load. Further, as discussed below, BYONC will also be Capacity Resources, but will be a subset of Capacity Resources that have arrangements with New Large Loads, must meet the BYONC RPM participation requirements discussed below, and also must meet all applicable requirements for Capacity Resources.¹³⁸

In addition, defining BYONC as simply MW provides significant flexibility in how New Large Loads meet their capacity requirements and how resources can provide BYONC to New Large Loads, and provide a more liquid marketplace for matching New Large Loads with BYONC. For example, a New Large Load can enter into BYONC arrangements with multiple qualifying resources to cover its peak load, and likewise, a resource can provide MW for purposes of entering into BYONC arrangements with multiple New Large Loads so long as these arrangements are clearly identified and consistent with the Large Load Registry. Through this approach of commoditizing the capacity attributes of a physical resource, the lumpiness inherent in matching New Large

¹³⁶ See proposed Tariff, Definitions – Bring Your Own New Capacity.

¹³⁷ See RAA, Article 1, Definitions (“‘Capacity Resources’ shall mean megawatts”); see also *Energy Harbor, LLC v. FERC*, 143 F.4th 388, 394 (D.C. Cir. 2025) (“The [PJM] Tariff defines a Capacity Resource as the amount of net megawatts committed from one or many generating units, not a physical facility.” (citation omitted)).

¹³⁸ See proposed Tariff, Attachment DD-4, section VI.

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Loads with physical resources is smoothed, allowing for a more efficient and timely means of addressing the capacity shortfall otherwise caused by the addition of New Large Loads.

Third, the capacity must be “new.” Given that PJM is currently short of capacity and looking to reestablish a healthy capacity reserve margin, PJM is proposing that any capacity added to the system starting with the 2027/2028 BRA will qualify as new—subject to the gating criteria discussed below, while capacity already on the system would not fall within the definition of BYONC.

For the same reason, PJM is proposing that “[m]egawatts of Unforced Capacity that have been previously included in an FRR Capacity Plan prior to the 2027/2028 Delivery Year do not qualify as BYONC.”¹³⁹ The capacity must be new to the PJM system, not just new to the capacity market.¹⁴⁰ As such, New Large Loads should only be exempted from IRAS if it has arrangements with capacity not already on the system as of May 31, 2027, the day before IRAS becomes available as a tool for PJM operators.

However, in the event the PJM Region has sufficient capacity to meet the PJM Region Reliability Requirement for three consecutive Delivery Years, the IRAS rules will not apply—no IRAS will be required, and BYONC will not be needed to address New Large Loads’ capacity needs. In such circumstance, all existing BYONC would be relieved of their BYONC market participation requirements and can be just regular Capacity Resources.¹⁴¹ But, to the extent the PJM Region again falls short of securing sufficient

¹³⁹ See proposed Tariff, Definitions – Bring Your Own New Capacity.

¹⁴⁰ See proposed RAA, Schedule 8.1, section D 1.1 (“An FRR Entity may not include in its FRR Capacity Plan any MW quantity of Existing Generation Capacity Resource in excess of what such FRR Entity owned or contracted by such FRR Entity prior to June 1, 2027, to serve New Large Load.”).

¹⁴¹ See proposed Tariff, Attachment DD-4, section IV(b)(iii).

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capacity to meet the PJM Regional Reliability Requirement and the need for IRAS arises, then the “new” capacity needed will no longer be measured against the capacity in the system prior to the 2027/2028 Delivery Year. Rather, it will be measured against the capacity supply existing at that time, such that BYONC would be any new capacity that has “not cleared in an RPM Auction conducted for a Delivery Year prior to the first Delivery Year” in which the PJM Region is short of capacity, while still meeting the gating criteria.¹⁴²

- b. PJM is proposing reasonable gating criteria designed to stimulate development of new capacity.

Such new capacity may be supported by generation, storage, or demand-side resources that meet certain gating criteria. The gating criteria are designed to ensure that the capacity is “new” and not a repackaging of existing capacity or capability.

Thus, for generation and storage resources, PJM proposes that the BYONC must be supported by: “(1) a new-build generation resource including new resources that obtain Capacity Interconnection Rights [(“CIR”)] transferred from deactivated resources or resources that have announced deactivation as of April 10, 2026; (2) the incremental capacity created by an uprate of Existing Generation Capacity Resources, but only to the extent such incremental capacity is created through an increase in such Generation Capacity Resource’s installed capacity and increase in [CIRs] associated with that Generation Capacity Resource; (3) the incremental capacity created by the utilization of Surplus Interconnection Service; (4) repowering of a deactivated generation resource that

¹⁴² See proposed Tariff, Attachment DD-4, section VI(a)(ii).

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deactivated prior to April 10, 2026; or (5) incremental capacity, whether due to greater Unforced Capacity or a higher level of [CIRs], created by an Existing Generation Capacity Resource's changing fuel type to a more efficient fuel type.”¹⁴³ Each of these gating criteria ensures that the BYONC will be capacity that was not on the transmission system or otherwise available to meet the PJM Region's needs as of June 1, 2027.

Because capacity may also be supplied by demand-side resources, PJM proposes that BYONC may be supported by Planned Demand Resource or Planned Distributed Energy Resources (“DER”) Capacity Aggregation Resources, as described in RAA, Schedule 6 and Schedule 6.2. Such resources would need to be composed of registered locations that did not previously support a capacity commitment or reduce the amount of capacity needed to meet the PJM Region Reliability Requirement through a Peak Shaving Adjustment or Price Responsive Demand for or prior to the 2026/2027 Delivery Year.¹⁴⁴ Thus, just as for BYONC supported by generation and storage resources, demand-side BYONC would need to be “new” starting June 1, 2027. However, this date would need to be reset in the event the PJM Region has sufficient capacity to meet the PJM Region Reliability Requirement for three consecutive Delivery Years—meaning the IRAS rules would not apply and BYONC will not be needed—and then the PJM Region again falls short of securing sufficient capacity to meet the PJM Regional Reliability Requirement. As discussed, such capacity shortage would trigger the need for IRAS again. In such circumstance, because the “new” capacity would need to be measured against the capacity

¹⁴³ See proposed Tariff, Attachment DD-4, sections VI(b)(i)(1)-(5).

¹⁴⁴ See proposed Tariff, Attachment DD-4, sections VI(b)(ii)(1)-(2).

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supply existing at that time, any demand-supported capacity would need to be “composed of, or reliant on, any location registered in the Delivery Year prior to the first Delivery Year” the PJM Region experienced the capacity shortage.¹⁴⁵

3. *To ensure the capacity benefits of BYONC are real and lasting, PJM is proposing certain RPM participation requirements.*

For BYONC to address the capacity needs of New Large Loads, BYONC must be Capacity Resources, with all attendant rights and obligations, and obtain capacity commitments. PJM is proposing a number of RPM participation requirements designed to obtain the maximum capacity benefit from the BYONC.

First, all BYONC must be Capacity Resources,¹⁴⁶ and when committed through an RPM Auction to provide capacity, the BYONC “will be subject to all capacity market rules, as set forth in Tariff, Attachments DD and DD-1.”¹⁴⁷ While these requirements may seem obvious, they make clear to all entities the rules and obligations that accompany arrangements between the UCAP of their resource and New Large Loads. Thus, if the resource supporting BYONC fails to appear or is otherwise unavailable for a Delivery Year, the seller will be subject to “all relevant deficiency charges under Tariff, Attachment DD.”¹⁴⁸

Second, to ensure that BYONC clear the auction and obtain a capacity commitment, PJM proposes a general requirement that each BYONC must participate, as a price taker (i.e., \$0/MW offer) in RPM Auctions for 10 consecutive Delivery Years, starting with the

¹⁴⁵ Proposed Tariff, Attachment DD-4, section VI(b)(ii)(1).

¹⁴⁶ See proposed Tariff, Attachment DD-4, section VIII(a).

¹⁴⁷ Proposed Tariff, Attachment DD-4, section VIII(c).

¹⁴⁸ Proposed Tariff, Attachment DD-4, section VIII(d).

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first Delivery Year of the arrangement with New Large Load.¹⁴⁹ As part of this 10-year participation requirement, PJM is proposing that the BYONC would be subject to the “capacity must-offer requirements and exceptions set forth in Tariff, Attachment DD, sections 6.6 and 6.6A,” and that the BYONC would be prohibited from “seek[ing] an exception to the capacity must-offer requirement to provide an external sale” during this 10-year period.¹⁵⁰

The 10-year participation requirement for generation and storage resources, including the no-external-sale rule, is just and reasonable. It is designed to ensure that this BYONC is real and lasting. New capacity brought to address a New Large Load’s significant capacity demands should not be allowed to sell its capacity attributes outside of PJM. Such would undermine the purpose of BYONC, particularly given that New Large Loads with BYONC arrangements are included in the demand curve. If the new capacity was able to withdraw from serving as a PJM Capacity Resource, but the load continued to be considered in the VRR Curve, then the New Large Load would no longer be the entity responsible for procuring its capacity. Rather, that obligation would have been transferred to PJM and shared with other PJM loads, contrary to the purpose of the IRAS scheme.

BYONC supported by a Demand Resource or DER Capacity Aggregation Resource likewise has a 10-year commitment.¹⁵¹ However, the seller of the BYONC may replace its

¹⁴⁹ See proposed Tariff, Attachment DD-4, section VIII(e).

¹⁵⁰ Proposed Tariff, Attachment DD-4, section VIII(b).

¹⁵¹ See proposed Tariff, Attachment DD-4, section VIII(e) (“To the extent the resource is a Demand Resource or DER Capacity Aggregation Resource, the BYONC shall participate in RPM Auctions for ten (10) consecutive Delivery Years as an Annual Demand Resource or DER Capacity Aggregation Resource, as applicable.”).

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BYONC obligation with a different BYONC subject to certain conditions. First, the initial BYONC seller (i.e., the releasing BYONC) must report—or cause to be reported—the new arrangement with the replacement BYONC in accordance with the reporting rules, and the replacement BYONC seller will need to provide the certification attesting to the arrangement. Second, the replacement BYONC must be for the remainder of the releasing BYONC’s 10-year commitment. And, third, the releasing BYONC (and its supporting registrations) may no longer provide BYONC going forward.¹⁵²

This exception to the 10-year commitment for demand-supported BYONC is just and reasonable, as it increases commercial opportunities for BYONC without adversely affecting the region’s ability to address its capacity needs. PJM understands that this exception provides New Large Loads a “bridge to power” of near-term demand-supported capacity that is eventually replaced with new generation as that supply comes online. As such, it increases opportunities for New Large Loads to spur the development of additional capacity in a few years, while relying on existing (or their own) demand-side capacity capability.

The requirement to offer BYONC MW as price takers (\$0/MW) is both just and reasonable. To realize the capacity benefits of a BYONC arrangement, the resource must successfully clear an RPM Auction and secure a capacity commitment. The BYONC arrangement itself serves as the commitment to provide this capacity. Because the resource is already obligated to provide the capacity, its incremental, going-forward avoidable costs

¹⁵² See proposed Tariff, Attachment DD-4, section VIII(e).

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to secure the RPM commitment are zero. Offering as a price taker directly reflects this zero-cost profile and guarantees the resource clears the auction.

This treatment also preserves market balance. Matching the inclusion of New Large Loads in the VRR Curve (demand side) with the corresponding BYONC MW in the supply stack at \$0/MW creates a symmetrical, one-for-one addition. This structure prevents artificial price shifts, resulting in an effectively price-neutral outcome for the rest of the market. This mechanism is consistent with existing Commission-approved rules for other resources retained for reliability purposes, which are also treated as price takers.¹⁵³

Finally, however, BYONC RPM participation requirements are extinguished if IRAS is not needed for three consecutive Delivery Years.¹⁵⁴ This means that the BYONC would no longer be required to offer as price takers for the remainder of their 10-year term. Because they are Capacity Resources BYONC would still be subject to the capacity must-offer requirement (to the extent they are not supported by Demand Resources or DER Capacity Aggregation Resources). But, they would be free to meet the requirements for an exception based on an external sale.

¹⁵³ See, e.g., *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088, at P 50, *reh'g denied*, 192 FERC ¶ 61,135, at PP 31-34 (2025); *Indep. Power Producers of N.Y. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,214 (2015), *order granting in part & denying in part clarification & reh'g*, 170 FERC ¶ 61,118 (2020); *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 (2015), *order on reh'g & compliance*, 155 FERC ¶ 61,076 (2016), *order on reh'g & compliance*, 161 FERC ¶ 61,189 (2017), *order on clarification & reh'g*, 163 FERC ¶ 61,047 (2018); see also *ISO New Eng. Inc.*, 165 FERC ¶ 61,202, at PP 82-88 (2018) (approving price taker treatment for resource retained for fuel security purposes), *order addressing arguments raised on reh'g*, 173 FERC ¶ 61,204 (2020).

¹⁵⁴ See proposed Tariff, Attachment DD-4, section VIII(f).

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4. *Reporting arrangements between BYONC and New Large Loads, and obligations on BYONC of an arrangement*

The purpose of the BYONC construct is to incent New Large Loads to facilitate the development of new capacity so that the PJM Region has sufficient capacity to maintain reliability without entering into a capacity shortage and/or having to shed existing native load customers. To do so, the New Large Loads need to be able to get credit for any BYONC they facilitate.¹⁵⁵ PJM proposes to give them credit by allowing New Large Loads to report to PJM an arrangement the New Large Load enters into with BYONC, and such arrangement will result in a reduction in the New Large Loads MW available to provide Interim Resource Adequacy Service.

a. The clear two-step process for PJM to recognize arrangements between New Large Loads and BYONC

Obtaining recognition for arrangements between BYONC with a New Large Load is a relatively basic process, with only two steps. One, an entity needs to report the arrangement to PJM by identifying both the New Large Load and the BYONC. While PJM expects the LSE serving the New Large Load or the applicable Electric Distributor to make such report, the proposed rules contemplate that PJM “may also accept information to the extent interconnection customers, Large Loads, Transmission Owners, or other entities voluntarily report any BYONC that may be in an arrangement with a New Large Load.”¹⁵⁶

Two, “the resource owner or entity with contractual authority to enter into a BYONC arrangement must certify” to PJM that the BYONC has an arrangement with that

¹⁵⁵ See proposed Tariff, Attachment DD-4, section V(c) (“For purposes of removing its eligibility to provide Interim Resource Adequacy Service, a New Large Load may enter into arrangements with BYONC supported by one or more resources.”).

¹⁵⁶ Proposed Tariff, Attachment DD-4, section VII(a)(i).

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New Large Load and that the BYONC will follow the RPM participation requirements in proposed Tariff, Attachment DD-4, section VIII.¹⁵⁷ Both elements of this certification are crucial. The BYONC representative attesting to the arrangement confirms the reported arrangement in the other step, providing certainty that the New Large Load's capacity needs will be addressed (at least in part) through this BYONC. Certification that the BYONC is aware of and intends to abide by the RPM participation requirements, which as discussed above, include a 10-year must-offer at \$0/MW, provides a level of certainty that the BYONC will be real and lasting. Together, these certifications provide confidence that the capacity needs of the New Large Load will be addressed (at least in part as discussed below in Part II.C.6) by this BYONC, allowing PJM to include such loads in the demand curve used to clear RPM Auctions.

- b. Arrangements must be reported to PJM in a timely manner to allow for them to be reflected in the RPM Auctions, because an arrangement will not be effective for Delivery Years before the BYONC clears an RPM Auction.

Because New Large Loads in arrangements with BYONC will be included in the VRR Curve used to clear RPM Auctions—and the BYONC in the arrangement will be required to participate in RPM Auctions as price takers, it is important that any BYONC arrangements expected to start in a future Delivery Year are timely reported to PJM to allow such load to be reflected in the VRR Curve. Without timely reporting, the BYONC could clear the auction without associated load being included in the demand curve, which

¹⁵⁷ Proposed Tariff, Attachment DD-4, section VII(a)(ii).

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would artificially show more capacity available to serve the PJM Region generally than would be appropriate.

To be clear, arrangements between New Large Loads and new resources need to be reported prior to the first Delivery Year they will be in place. PJM will validate the arrangement as discussed, and update the Large Load Registry to reflect any PJM-validated arrangements between New Large Loads and BYONC. That is, PJM will validate the BYONC to make sure it meets the BYONC rules and is capable of providing the level of capacity, and to avoid duplicate arrangements between BYONC and New Large Loads, and PJM will, as necessary, validate the data regarding the New Large Load with the Electric Distributor that interconnected the Large Load for retail service.¹⁵⁸

The above timing concerns are most present where the arrangement is known or has otherwise been consummated. Thus, PJM proposes rules requiring timely reporting of BYONC-New Large Load arrangements prior to the next RPM Auction for the first Delivery Year of each arrangement.

i. Reporting BYONC-New Large Load arrangements for the 2027/2028 and 2028/2029 Delivery Years

For the 2027/2028 and 2028/2029 Delivery Years, because (1) the BRAs have already run; (2) IRAS is not intended to commence until June 1, 2027; and (3) parties need time to develop appropriate contractual arrangements, PJM proposes that, for an arrangement to be considered in determining a New Large Load's availability to provide IRAS, as measured by its Eligible New Large Load Amount, any arrangement for these

¹⁵⁸ Once an arrangement is reported to PJM, there are no ongoing reporting requirements for subsequent Delivery Years.

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Delivery Years must be reported to PJM by April 1 before the first applicable Delivery Year.¹⁵⁹ Reporting arrangements between BYONC and New Large Loads by such date will afford PJM sufficient time to review and validate, and then update the Large Load Registry by April 15 before the Delivery Year.¹⁶⁰ PJM will use such data to determine the amount of IRAS available to PJM for the upcoming Delivery Year, and assign each Electric Distributor the amount of IRAS available in their zone/area for the Delivery Year.

*ii. Reporting BYONC-New Large Load arrangements
for the 2029/2030 Delivery Year*

The timing considerations for Delivery Year 2029/2030 are idiosyncratic given that the BRA is scheduled to commence on December 9, 2026, i.e., within 60 days from the requested effective date of this filing. Accordingly, PJM is proposing that any known arrangements be reported to PJM “no later than by 50 days prior to the commencement of the 2029/2030 Base Residual Auction,”¹⁶¹ so that PJM may adjust the VRR Curve for that auction, as discussed below in Part II.F. In the event, an arrangement is entered into after that deadline, in order for the “BYONC arrangement to be considered” for the 2029/2030 Delivery Year, and the New Large Load’s Interim Resource Adequacy Service availability to be reduced, the arrangement must be reported “by 30 days prior to the posting of the planning parameters for the Incremental Auctions arrangement with the 2029/2030 Delivery Year.”¹⁶²

¹⁵⁹ See proposed Tariff, Attachment DD-4, section VII(b).

¹⁶⁰ See proposed Tariff, Attachment DD-4, section VII(b).

¹⁶¹ Proposed Tariff, Attachment DD-4, section VII(c).

¹⁶² Proposed Tariff, Attachment DD-4, section VII(c).

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iii. *Reporting BYONC-New Large Load arrangements for the 2030/2031 Delivery Year and subsequent Delivery Years*

Starting with the 2030/2031 Delivery Year and for all future Delivery Years, for any BYONC arrangement to be considered for a given Delivery Year, the arrangement must be reported to PJM “no later than by 30 days prior to the posting of the planning parameters for the relevant RPM Auction for the initial Delivery Year the BYONC enters into an arrangement with the New Large Load.”¹⁶³ Reporting associations 30 days before PJM must post the planning parameters for an RPM Auction provides sufficient time for PJM to validate the information provided and reflect such arrangement in the VRR Curve for that auction. It also reasonably balances providing entities the maximum time possible to agree on the arrangements.

c. Rules for BYONC arrangements

PJM is also proposing certain rules around BYONC-New Large Load arrangements to ensure no capacity is double counted and to facilitate efficient matchmaking between New Large Loads and new capacity. As discussed above, BYONC is composed of MW, not a physical resource. This allows for efficient sizing of BYONC to meet the exact capacity needs of New Large Loads, and allows for liquidity in the market for matching the two.

In this regard, PJM proposes that “[a] physical resource may support multiple BYONC, each of which may be in an arrangement with different New Large Loads, as long

¹⁶³ Proposed Tariff, Attachment DD-4, section VII(d).

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as no BYONC is in an arrangement with more than one New Large Load,”¹⁶⁴ and that “[a] New Large Load may enter into an arrangement with discrete BYONC supported by different physical resources.”¹⁶⁵ In other words, New Large Load may reduce or eliminate its IRAS availability by mixing and matching BYONC supported by many different physical resource, with the caveat that no MW of BYONC may sold twice. This approach best allows resources to price each MW of BYONC capability and derive an alternative revenue stream that will facilitate the development of new capacity in PJM.

To provide further flexibility, PJM is proposing that “[a] New Large Load may enter into an arrangement with BYONC in excess of its current Eligible Large Load Amount, e.g., to allow for expected growth in the New Large Load.”¹⁶⁶ Thus, a New Large Load that has plans for expanding in the future may go ahead and lock in BYONC for such planned growth before the growth occurs. This type of arrangement would occur where the new capacity enters commercial operation at its maximum facility output level while the New Large Load has not achieved its maximum expected demand level. Offering this flexibility to the New Large Load and BYONC arrangements is reasonable, as it allows the parties to fashion their arrangements however they see fit.

While PJM is proposing significant flexibility in reaching BYONC-New Large Load arrangements, PJM is proposing that once the subject of an arrangement BYONC cannot change to a different New Large Load—i.e., BYONC is non-transferable. Specifically, PJM is proposing that “BYONC that is in an arrangement with a New Large

¹⁶⁴ Proposed Tariff, Attachment DD-4, section VII(f).

¹⁶⁵ Proposed Tariff, Attachment DD-4, section VII(g).

¹⁶⁶ Proposed Tariff, Attachment DD-4, section VII(h).

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Load must remain in such arrangement with that New Large Load unless and until the New Large Load is permanently out-of-service.”¹⁶⁷ This limitation is necessary and consistent with PJM’s overall scheme. Specifically, PJM is proposing that once BYONC is in an arrangement with a New Large Load, such arrangement is permanent,¹⁶⁸ and the New Large Load gets the benefit of “bringing” this new capacity to the system and permanently reduces its availability to provide Interim Resource Adequacy Service by the ICAP equivalent of the BYONC.¹⁶⁹ Allowing BYONC to leave or be traded after entering into an arrangement with a New Large Load would dramatically increase the complexity of the program without commensurate benefit. New Large Loads would be susceptible to fluctuations in their Interim Resource Adequacy Service availability, and could be left scrambling for additional BYONC. PJM would need to expend extra resources ensuring no BYONC enters into an arrangement with New Large Load more than once.

- d. The Accredited UCAP value for BYONC subject to an arrangement is set in the first Delivery Year the arrangement is in effect.

The timing of the arrangement is central to the determination of the BYONC’s Accredited UCAP value—the ICAP equivalent of this Accredited UCAP value is used to

¹⁶⁷ Proposed Tariff, Attachment DD-4, section VII(e).

¹⁶⁸ As discussed, PJM is proposing that BYONC based on Demand Resources or DER Capacity Aggregation Resources may be replaced within the 10-year RPM Auction commitment. This does not affect the requirement the BYONC is permanent, as the Demand Resources or DER Capacity Aggregation Resources being replaced must be retired and their registered locations can never support future BYONC. See proposed Tariff, Attachment DD-4, section VIII(e) (“[T]he replaced BYONC (and its supporting registrations) may no longer provide BYONC.”).

¹⁶⁹ See proposed Tariff, Attachment DD-4, section V(b) (determination of a New Large Load’s Eligible New Large Load Amount).

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reduce a New Large Load's potential IRAS availability as discussed below in Part II.C.7.¹⁷⁰

For BYONC supported by any resource type (generation, storage, and demand-side), the Accredited UCAP of the BYONC "shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load."¹⁷¹ For BYONC supported by Demand Resources or DER Capacity Aggregation Resources, such Accredited UCAP value "must be demonstrated each year for a 10-year period using the Demand Response or DER Capacity Aggregation Resources installed capacity for the first Delivery Year after the BYONC is in an arrangement with the New Large Load."¹⁷² This requirement is derived from PJM's existing Demand Resource rules, which require sellers to the "demonstrate, to PJM's satisfaction, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed."¹⁷³ However, given the 10-year commitment for BYONC, the usual one-year demonstration must extend to cover all 10 years. This is reasonable, as it provides a level of assurance that the capacity to be provided by such demand-side resource is commensurate with that offered by a generation or storage resource.

¹⁷⁰ See proposed Tariff, Attachment DD-4, section V(b) ("A New Large Load's Eligible New Large Load Amount shall be determined as follows: (New Large Load's registered peak load (in MW), as provided in the Large Load Registry) minus (the sum of all BYONC arrangements with the New Large Load in accordance with Tariff, Attachment DD-4, section VII divided by the Forecast Pool Requirement for the first Delivery Year in which the BYONC cleared an RPM Auction, plus Allocated RBP UCAP MW assigned to the New Large Load, in accordance with Tariff, Attachment DD-4, section IX divided by the Forecast Pool Requirement for the first Delivery Year in which the Allocated RBP UCAP MW cleared an RPM Auction).").

¹⁷¹ Proposed Tariff, Attachment DD-4, sections VII(i)(i)-(ii).

¹⁷² Proposed Tariff, Attachment DD-4, section VII(i)(ii).

¹⁷³ RAA, Schedule 6, section A.5.

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5. *Allocated RBP UCAP MW*

In addition to BYONC, a New Large Load may have its IRAS availability reduced by being allocated a share of the RBP UCAP MW¹⁷⁴ obtained through the Reliability Backstop Procurement that PJM has proposed in Docket No. ER26-3380.¹⁷⁵

Under the proposed RBP rules, the costs for committed RBP UCAP MW are, as a general matter, allocated to each Electric Distributor's zones/areas based on its pro-rata share of forecasted load growth in the PJM Region from the 2026/2027 Delivery Year to the 2028/2029 Delivery Year.¹⁷⁶ To do so, PJM used the total load growth, in part to determine the target quantity to be committed through the Reliability Backstop Procurement, called the "Final RBP Target," and provided that costs for such resources will be allocated "an Electric Distributor's zone/area on a pro-rata basis using the zone/area's assigned share of the total Final RBP Target MW across all zone/areas."¹⁷⁷ In other words, those areas that have forecasted load growth—which is generally due to Large Loads, including New Large Loads—will be allocated the costs for the RBP UCAP MW.

For purposes of IRAS availability, PJM proposes that the allocation of RBP UCAP MW following the RBP cost allocation at the Electric Distributor zone/area level, such that each Electric Distributor zone/area "shall be allocated RBP UCAP MW on a pro-rata basis

¹⁷⁴ RBP UCAP MW is the unforced capacity product committed through the RBP.

¹⁷⁵ RBP Proposal Filing, Transmittal Letter at 46.

¹⁷⁶ See RBP Proposal Filing, proposed Tariff (Attachments A & B), Attachment DD, section 18.3(a) ("The Office of the Interconnection shall allocate the Initial RBP Target MW to each Electric Distributor's zone/area using that zone/area's pro-rata share of the difference between the forecasted Load Adjustments for the 2026/2027 Delivery Year and the 2028/2029 Delivery Year. . . . The resulting reduced MW, floored at zero, is used to calculate the zone/area's assigned pro-rata share of the Final RBP Target MW. The zone/area's assigned share of the Final RBP Target MW shall remain constant throughout the fixed, 15-year term.").

¹⁷⁷ RBP Proposal Filing, proposed Tariff (Attachments A & B), Attachment DD, section 18.3(a).

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using the Electric Distributor zone/area's assigned share of the total Final RBP Target MW across all zone/areas."¹⁷⁸ From there, to allocate that quantity among New Large Load's in the Electric Distributor's zone/area, PJM proposes that the Electric Distributor "shall inform [PJM] how such RBP UCAP MW should be further allocated among the New Large Loads located in the Electric Distributor's zone/area."¹⁷⁹ But, in the event the Electric Distributor has not informed PJM how to allocated its share of RBP UCAP MW among its New Large Loads by April 1 before a given Delivery Year, PJM will allocate that quantity pro rata among the New Large Loads in the zone/area.¹⁸⁰ Since RBP commitments can vary each Delivery Year as RBP Resources enter commercial operation, the allocation of RBP UCAP MW will be done for each Delivery Year throughout the 15-year RBP commitment term, i.e., from 2028/2029 through 2042/2043.

PJM's proposed approach is just and reasonable. The "benefit" of RBP UCAP MW in the context of IRAS should flow to the entities with cost responsibility for the RBP UCAP MW. Thus, New Large Loads should get an offset credit to their capacity needs for RBP UCAP MW.

¹⁷⁸ Proposed Tariff, Attachment DD-4, section IX(a).

¹⁷⁹ Proposed Tariff, Attachment DD-4, section IX(b)(i). Each New Large Load's allocated share of its zone/area's RBP UCAP MW is called "Allocated RBP UCAP MW." See proposed Tariff, Definitions – Allocated RBP UCAP MW.

¹⁸⁰ Proposed Tariff, Attachment DD-4, section IX(b)(ii).

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6. *Only Eligible New Large Loads will be considered available to provide Interim Resource Adequacy Service, and then only to the extent they do not have sufficient BYONC to meet their capacity needs.*

All New Large Loads shall be eligible to provide IRAS and considered Eligible New Large Loads¹⁸¹ to the extent the combination of their BYONC arrangements and Allocated RBP UCAP MW does not meet their capacity needs.¹⁸² To determine whether a New Large Load is an Eligible New Large Load, PJM will determine its Eligible New Large Load Amount—a measurement of the difference between the New Large Load’s peak load (in MW) as reported in the New Large Load Registry and the ICAP equivalent of its (1) BYONC arrangements and (2) Allocated RBP UCAP MW.¹⁸³ If the Eligible New Large Load Amount is greater than zero MW, the New Large Load is an Eligible New Large Load.¹⁸⁴

¹⁸¹ See proposed Tariff, Definitions – Eligible New Large Load (“‘Eligible New Large Loads’ shall mean a New Large Load eligible to provide Interim Resource Adequacy Service in accordance with Tariff, Attachment DD-4, section V.”).

¹⁸² See proposed Tariff, Attachment DD-4, section V(a); see also proposed Tariff, Attachment DD-4, section IV(a) (“All Eligible New Large Loads shall be available to be requested to provide Interim Resource Adequacy Service by [PJM].”).

¹⁸³ See proposed Tariff, Attachment DD-4, section V(b) (“A New Large Load’s Eligible New Large Load Amount shall be determined as follows: (New Large Load’s registered peak load (in MW), as provided in the Large Load Registry) minus (the sum of all BYONC arrangements with the New Large Load in accordance with Tariff, Attachment DD-4, section VII divided by the Forecast Pool Requirement for the first Delivery Year in which the BYONC cleared an RPM Auction, plus Allocated RBP UCAP MW assigned to the New Large Load, in accordance with Tariff, Attachment DD-4, section IX divided by the Forecast Pool Requirement for the first Delivery Year in which the Allocated RBP UCAP MW cleared an RPM Auction).”).

¹⁸⁴ See proposed Tariff, Attachment DD-4, section V(a) (“New Large Loads with a cumulative installed capacity equivalent of their BYONC arrangements and assigned Allocated RBP UCAP MW that equals or exceeds the New Large Load’s registered peak load, as provided in the Large Load Registry, shall not be Eligible New Large Loads. New Large Loads that are located within an FRR Service Area cannot be Eligible New Large Loads.”).

¹⁸⁴ See proposed Tariff, Attachment DD-4, section V(a). This is reasonable given that FRR Entities are individually responsible for securing sufficient capacity for all loads within their FRR Service Area, and are therefore not reliant on RPM to secure capacity commitments.

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7. *Determination of the maximum amount of Interim Resource Adequacy Service available for a Delivery Year for the PJM Region and each Electric Distributor zone/area.*

The amount of Interim Resource Adequacy Service PJM may need to be available will be determined each Delivery Year for the PJM Region and each Electric Distributor zone/area. The amount of Interim Resource Adequacy Service needed to be available depends on the level of capacity shortfall for the PJM Region and the Eligible New Large Load Amounts.

There are three possible scenarios. One, the capacity shortfall¹⁸⁵ exceeds the cumulative sum of all Eligible New Large Load Amounts across the PJM Region. In this event, then PJM will need all Eligible New Large Load Amounts to be available to provide Interim Resource Adequacy Service for that Delivery Year.¹⁸⁶

Two, the capacity shortfall is less than the cumulative sum of all Eligible New Large Load Amounts across the PJM Region. In this event, then PJM only needs Eligible New Large Loads to make available Interim Resource Adequacy Service in a cumulative amount equal to the capacity shortfall.¹⁸⁷

¹⁸⁵ To use the most precise figure, the capacity shortfall shall be determined after the Third Incremental Auction and equal: “[amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor.” Proposed Tariff, Attachment DD-4, section IV(b)(i).

¹⁸⁶ See proposed Tariff, Attachment DD-4, section IV(b)(i).

¹⁸⁷ See proposed Tariff, Attachment DD-4, section IV(b)(ii) (“In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount less than the sum (in MW) of all Eligible New Large Load Amounts, then the difference (in MW) shall be the cumulative amount (in MW) of Eligible New Large Load Amounts that the Office of the Interconnection needs to be available to provide Interim Resource Adequacy Service for that Delivery Year.”).

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Third, there is no capacity shortfall, i.e., “([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) equals or exceeds the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor)” and PJM “does not need any Eligible New Large Loads to be available to provide Interim Resource Adequacy Service for that Delivery Year.”¹⁸⁸

If the first or second scenarios occur, PJM will need to determine for the Delivery Year the total amount of IRAS needed to be available on a daily basis across the PJM Region and for each Electric Distributor zone/area.¹⁸⁹ The regional amount will be the lesser of: the cumulative sum of all Eligible New Large Load Amounts across the PJM Region or the capacity shortfall.¹⁹⁰ In either instance, the maximum amount of IRAS PJM needs from an Electric Distributor zone/area will be determined in accordance with the following formula:

the product of the sum of all Eligible New Large Load Amounts needed in the PJM Region pursuant to Attachment DD-4, section IV(b) multiplied by the quotient of [(the sum of all Eligible New Large Load Amounts in the Electric Distributor’s zone/area) divided by (the sum of all Eligible New Large Load Amounts in the PJM Region)].¹⁹¹

In other words, each Electric Distributor zone/area will be required to provide a proportional share of the IRAS needed based on the sum of the Eligible New Large Load Amounts in its zone/area. Thought of conversely, each Electric Distributor zone/area will

¹⁸⁸ Proposed Tariff, Attachment DD-4, section IV(b)(iii).

¹⁸⁹ See proposed Tariff, Attachment DD-4, section IV(c).

¹⁹⁰ See proposed Tariff, Attachment DD-4, section IV(c)(i).

¹⁹¹ See proposed Tariff, Attachment DD-4, section IV(c)(ii).

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need to be available to provide IRAS consistent with the amount of capacity the Eligible New Large Loads in the zone/area need to meet the zone/area's capacity needs.

As discussed above in Parts II.C.2.a and II.C.3, to the extent the third scenario (i.e., PJM does *not* have a capacity shortfall) occurs for three consecutive Delivery Years, then the IRAS program effectively goes to sleep, with any existing BYONC relieved of their RPM participation obligations¹⁹² and all New Large Loads effectively becoming Large Loads. The New Large Loads become Large Loads because the definition of New Large Load is initially tied to an in-service date of June 1, 2027, or later.¹⁹³

PJM is not proposing an end date to the IRAS program. Regardless of whether the PJM Region has maintained capacity sufficient to meet the PJM Region Reliability Requirement for three or more years, PJM will continue to maintain the Large Load Registry. However, if the region re-enters capacity shortfall conditions, then the need for New Large Loads to provide IRAS will re-emerge. The definition of New Large Load allows for this and explicitly provides that New Large Loads will then be defined as entering service “after June 1 of the first Delivery Year” the PJM Region is short of capacity.¹⁹⁴

¹⁹² Proposed Tariff, Attachment DD-4, section VIII(f).

¹⁹³ Proposed Tariff, Definitions – New Large Load.

¹⁹⁴ Proposed Tariff, Definitions – New Large Load. For example, to the extent PJM meets the regional capacity requirement for Delivery Years 2033/2034, 2034/2035, and 2035/2036, but then enters shortage conditions for the 2036/2037 Delivery Year, then New Large Loads must have an in-service date after June 1, 2036.

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8. *PJM is not proposing to extend IRAS to New Large Loads located in FRR Service Areas.*

A general purpose of IRAS is for New Large Loads to bring new capacity to address their capacity needs instead of relying on PJM's capacity market. Given that FRR Entities have elected to be responsible for providing capacity for *all* loads in their FRR Service Areas, there is no reason to extend IRAS to New Large Loads in FRR Service Areas. For this reason, as noted above, PJM is proposing that "New Large Loads that are located within an FRR Service Area cannot be Eligible New Large Loads."¹⁹⁵ While New Large Loads in FRR Service Areas may not be eligible for IRAS, they will still fall within the definition of Large Load and, as such, the LSEs serving such load—or another entity—will need to register such loads in the Large Load Registry.

However, FRR Entities must procure sufficient capacity for all their New Large Loads and include such in their FRR Capacity Plans. And, the PJM Region, as a whole, does not have excess capacity right now, so the FRR Entity must add new capacity for any New Large Load in its territory. Given the current levels of existing capacity, PJM is proposing a similar "bring your own new capacity" requirement for FRR Service Areas. While PJM will not set gating criteria for an FRR Entity's new capacity to serve New Large Loads, PJM is proposing a requirement that "[a]n FRR Entity may not include in its FRR Capacity Plan any MW quantity of Existing Generation Capacity Resource in excess of what such FRR Entity owned or contracted by such FRR Entity prior to June 1, 2027, to serve New Large Load" to meet its capacity requirements.¹⁹⁶ This rule ensures that FRR

¹⁹⁵ Proposed Tariff, Attachment DD-4, section V(a).

¹⁹⁶ See proposed RAA, Schedule 8.1, section D.1.1.

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Entities (or their New Large Loads) bring *new* capacity to the system to meet the New Large Loads' resource adequacy needs, and precludes FRR Entities from satisfying load growth from New Large Loads with existing Capacity Resources that could potentially be lured from the RPM Auctions (and further exacerbating the shortage conditions in the capacity market). The growth of Large Loads is an issue facing the entire PJM Region, and new capacity should arrive to serve their needs, regardless of whether the New Large Load is to be located in an FRR Service Area or the region served by RPM. At the same time, this measured approach provides FRR Entities with the necessary flexibility to replace contracts for capacity from one set of resources with a different set of resources that may be existing so long as the total MW quantity of Existing Generation Capacity Resource in the FRR Capacity Plan does not exceed the amount that such FRR Entity owned or contracted prior to June 1, 2027, to serve New Large Loads.

D. Load Reduction Under Interim Resource Adequacy Service

1. *Interim Resource Adequacy Service will be needed only to address potential capacity emergencies or IROL violations.*

IRAS is a supplemental capacity product through which Eligible New Large Loads may be directed by the Electric Distributor to reduce their load in response to an Interim Resource Adequacy Service Action called by PJM. Indeed, proposed Tariff, Attachment DD-4, section I(a) accurately describes Interim Resource Adequacy Service as “a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by [PJM] to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that are not in arrangements with new

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capacity additions to the PJM Region.” In other words, IRAS is needed to manage the capacity needs of New Large Loads that have not satisfied their capacity needs on their own.

Thus, “[s]tarting with the 2027/2028 Delivery Year, [PJM] may, in accordance with the Manuals, instruct the implementation of an Interim Resource Adequacy Service Action prior to calling on Pre-Emergency Load Management Reductions Actions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.”¹⁹⁷ In other words, PJM anticipates the need to implement IRAS when (1) it is no longer able to maintain reserves in the RTO or a zone; or (2) there are insufficient resources to keep IROLs within defined operating limits in order to prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection.

As detailed in the proposed Tariff language, PJM may initiate an Interim Resource Adequacy Service Action, which is an “Operating Instruction, as defined by NERC,”¹⁹⁸ in accordance with the procedures and conditions to be detailed in the Manuals, and “prior to calling on Pre-Emergency Load Management Reduction Actions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.”¹⁹⁹ The details as to how and when

¹⁹⁷ Proposed Tariff, Attachment DD-4, section I(b).

¹⁹⁸ Proposed Tariff, Definitions – Interim Resource Adequacy Service Action.

¹⁹⁹ Proposed Tariff, Attachment DD-4, section I(b).

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PJM may call an Interim Resource Adequacy Service Action will be set forth in PJM Manual 13.²⁰⁰

The affidavit of Mr. Christopher Pilon, Senior Director of Operations Planning for PJM, provides an overview of the steps taken by PJM Dispatchers, in accordance with PJM Manual 13, “to manage, allocate, or alleviate an emergency” in the course of Emergency Procedure Advisories, Alerts, Warnings, and Actions.²⁰¹

Interim Resource Adequacy Service may be called on, as necessary, to maintain required RTO/Zonal Reserves, IROLs within limits, and/or prevent cascading outages if available economic generation is not sufficient. To implement IRAS Emergency Procedures, PJM intends to revise PJM Manual 13 to include IRAS Alerts and IRAS Actions. Mr. Pilon further explains, in his affidavit, how Interim Resource Adequacy Service Alerts and Interim Resource Adequacy Service Actions will be added to the steps taken in the event of an emergency, and thus provide an additional tool that PJM Dispatchers may use when responding to an emergency.²⁰²

Importantly, however, while Interim Resource Adequacy Service Alerts and Interim Resource Adequacy Service Actions will be incorporated into a general sequence of escalating Emergency Procedures, Mr. Pilon notes that it remains the case that “PJM

²⁰⁰ CIFP Framework for Service at 4 (“New and/or existing Emergency Procedures (Alerts and Warnings) need to be adjusted as appropriate to provide advanced notice that Interim Resource Adequacy Service may need to be reduced. This will be documented in [PJM] Manual 13.”).

²⁰¹ Affidavit of Mr. Christopher Pilon on Behalf of PJM Interconnection, L.L.C. (Attachment C) ¶ 5 (“Pilon Aff.”) (quoting PJM Manual 13, section 2.1).

²⁰² Pilon Aff. ¶¶ 29-55.

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Dispatchers ‘have the flexibility to implement emergency procedures in whatever order is required to ensure system reliability.’²⁰³

That said, PJM anticipates that the general sequence of Emergency Procedures will be revised, as follows: Prior to the Operating Day, PJM may issue Interim Resource Adequacy Service Alerts, which would put all Eligible New Large Loads on notice that PJM may “request reductions in load in quantities equal to or lesser than each Electric Distributor zone/area’s assigned IRAS amounts during the next Operating Day.”²⁰⁴ Interim Resource Adequacy Service Alerts would be available before and/or concurrently with a Max Gen Alert/Load Management Alert.²⁰⁵ Mr. Pulong describes a scenario (Example 1), in which PJM operators look ahead to the next Operating Day and determine that it is necessary to issue an Interim Resource Adequacy Service Alert.²⁰⁶ As Mr. Pulong explains, “All alerts and cancellation thereof are broadcast on the ALLCALL system and posted to selected PJM websites to assure that all members receive the same information. Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages.”²⁰⁷

In real-time, as Mr. Pulong explains, Interim Resource Adequacy Service Actions would become a new step available to PJM Dispatchers, prior to Pre-Emergency Load Management Reductions.²⁰⁸ Mr. Pulong describes a scenario (Example 2) in which PJM

²⁰³ Pulong Aff. ¶ 15 (quoting PJM Manual 13, section 2.3) (footnotes omitted).

²⁰⁴ Pulong Aff. ¶ 31.

²⁰⁵ Pulong Aff. ¶ 31.

²⁰⁶ Pulong Aff. ¶¶ 29-34.

²⁰⁷ Pulong Aff. ¶ 33 (quoting PJM Manual 13, section 2.3.1).

²⁰⁸ Pulong Aff. ¶ 45.

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Dispatchers respond to an RTO-wide emergency in real-time by deploying an Interim Resource Adequacy Service Action under an EEA1.²⁰⁹

As Mr. Pilon explains, prior to deploying Interim Resource Adequacy Service Actions, PJM Dispatchers may first “deploy available generation and economic demand resources, in economic dispatch order while maintaining required reserves.”²¹⁰ Second, PJM Dispatchers may “require non-firm interchange transaction curtailment, as needed.”²¹¹ Third, assuming that “PJM’s new, yet-to-be-effective transmission service products—Non-Firm Contract Demand Service (‘CDS’) and Interim Network Integrated Transmission Service (‘Interim NITS’) are effective, PJM may direct curtailment of Non-Firm CDS and/or Interim NITS transmission service.”²¹²

In accordance with the proposed sequence, “after all non-firm transmission services are curtailed” PJM may “then issue the new Interim Resource Adequacy Service Action prior to deployment of a Pre-Emergency Load Management Reduction Action.”²¹³ PJM intends to communicate Emergency Procedures under IRAS using the status quo notification processes set forth in PJM Manual 13.²¹⁴ Figure 1, below, demonstrates how

²⁰⁹ Pilon Aff. ¶¶ 35-47.

²¹⁰ Pilon Aff. ¶ 36.

²¹¹ Pilon Aff. ¶ 37.

²¹² Pilon Aff. ¶ 12 (citing *PJM Interconnection*, 195 FERC ¶ 61,209 at P 551 (“[W]e find PJM’s proposal to curtail Interim NITS and [Non-Firm Contract Demand] transmission service prior to deployment of its Pre-Emergency Load Response Program, or in response to a transfer capability shortage as a result of system reliability conditions, to be just and reasonable because it is consistent with how Non-Firm [Point-to-Point Service] is curtailed. . . . [W]e find that PJM’s proposal to curtail Interim NITS during capacity or reserve shortages is just and reasonable and consistent with both the nature of the transmission service as a non-firm transmission service for which Eligible Customers do not pay generation capacity charges, and the need to maintain reliability.” (footnote omitted))); *id.* ¶ 39.

²¹³ Pilon Aff. ¶ 40.

²¹⁴ Pilon Aff. ¶ 41.

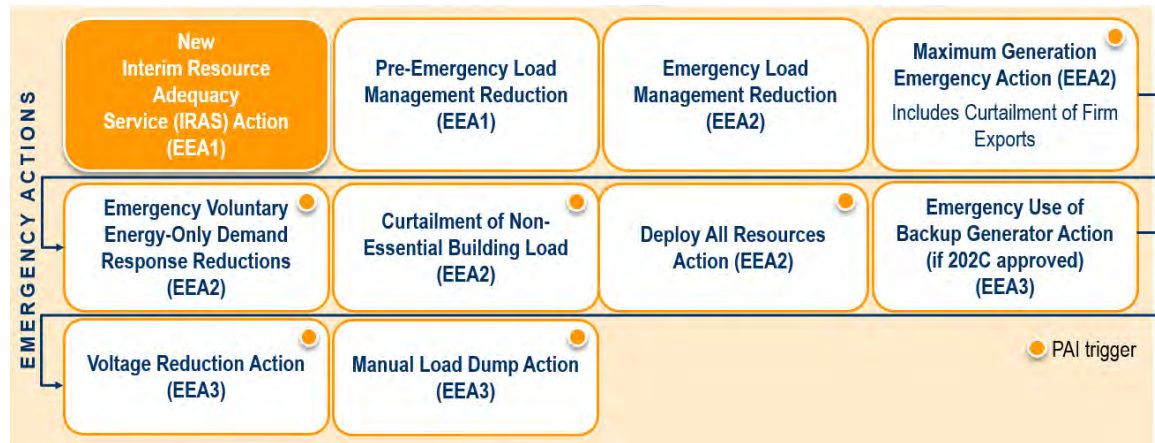
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New Interim Resource Adequacy Service Actions may precede Pre-Emergency Load Management Reductions in an EEA1.

Figure 1: PJM Emergency Procedures with Interim Resource Adequacy Service (IRAS)



As explained in PJM Manual 13, “EEA1 signals that PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.”²¹⁵ In other words, the region is approaching a capacity event. Thus, it is appropriate for PJM to direct Electric Distributors to reduce those New Large Loads that have failed to cover their capacity obligations *before* relying on Demand Resources, through Pre-Emergency Load Management Reductions Actions, to maintain reliability.

To further illustrate how PJM plans to integrate IRAS into its Emergency Procedures, PJM prepared Figure 2, which shows how IRAS will affect PJM’s Emergency Procedures, relative to the status quo, and when there is an order from the Secretary of

²¹⁵ PJM Manual 13, section 2.3.1.

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Energy under FPA section 202(c) authorizing backup generation to run in excess of their permits.²¹⁶

Figure 2: Comparison of PJM Emergency Procedures

	Alerts and Warnings	EEA1		EEA2	Last step before EEA3	EEA3
Today (Status quo)	Schedule All Available Resources; issue Max Gen Alert	Pre-Emergency DR		Emergency DR		Shed Non-critical load with backup generation (remaining load)
						firm load shed
Status quo plus DOE 202c Order	Schedule All Available Resources; issue Max Gen Alert	Pre-Emergency DR		Emergency DR	Emergency Use of Back-up Generators (pre 6/1/2027 load)	Shed Non-critical load with backup generation (remaining load)
						firm load shed
With IRAS	Schedule All Available Resources; issue IRAS and/or Max Gen Alerts	IRAS Large Load reduction (post 6/1/27 load) without BYONC	Pre-Emergency DR	Emergency DR	Emergency Use of Back-up Generators (pre 6/1/2027 load)	Shed Non-critical load with backup generation (remaining load)
						firm load shed

Finally, Figures 1 and 2 illustrate that changing the Emergency Procedures sequence to call on IRAS *after* Pre-emergency Load Management would reduce the incentive for New Large Loads to bring new capacity to the system, as they would be insulated by the Demand Resource capacity products.

²¹⁶ 16 U.S.C. § 824a(c).

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2. *How PJM will call an Interim Resource Adequacy Service Action*

Under the terms of the Operating Agreement and as the Reliability Coordinator, Transmission Operator, and Balancing Authority, PJM has the authority and flexibility to initiate Emergency Procedures as it sees fit to maintain the reliability of the PJM Region. Indeed, the Operating Agreement explicitly authorizes PJM to “[c]oordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, in order to preserve reliability in accordance with NERC, or Applicable Regional Entity principles, guidelines and standards, and to ensure the operation of the PJM Region in accordance with Good Utility Practice and this Agreement[.]”²¹⁷ where an “Emergency” is defined as mean “a condition that requires implementation of emergency procedures as defined in the PJM Manuals.”²¹⁸

Therefore, while the addition of IRAS Emergency Procedures will add to the sequence of escalating steps that PJM may take to respond to an emergency and prevent Manual Load Dump, Mr. Pilog also adds that, as set forth in PJM Manual 13, “the rapidness of system events influences the timing and order of actions necessary to maintain system reliability. PJM Dispatchers ‘have the flexibility to implement emergency procedures in whatever order is required to ensure system reliability. Likewise, they have the flexibility to exit emergency procedures in a different order than they were implemented.’”²¹⁹

²¹⁷ Operating Agreement, Schedule 1, section 1.6.2(vii).

²¹⁸ Operating Agreement, section 1, Definitions E – F (defining Emergency).

²¹⁹ Pilog Aff. ¶ 15 (quoting PJM Manual 13, section 2.3) (footnotes omitted).

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Thus, while IRAS and Pre-Emergency Load Management Reductions would both be categorized as EEA1 actions, the sequence of actions is such that PJM will generally call on IRAS before Pre-Emergency Load Management Reductions to address an Emergency, to the extent the zone/area has any IRAS available.

Furthermore, as Mr. Pilonig explains in his affidavit, PJM will issue MW load reduction directives to “Electric Distributors to implement reductions in load up to, and capped at, the pre-Delivery Year IRAS obligations they were assigned. Importantly, PJM will not direct specific New Large Loads to reduce load, even though Electric Distributors—in coordination, where applicable, with relevant states, Load Serving Entities, and New Large Loads—may issue more specific directives to specific retail customers. PJM will only direct load reduction of an aggregate MW IRAS within the zone or area.”²²⁰

In addition, PJM may deploy broader or more targeted IRAS Actions, as needed. In response to an RTO-wide emergency, for example, as Mr. Pilonig explains in Example 2, “based on the maximum IRAS amounts assigned to each Electric Distributor zone/area, PJM Dispatchers [may] call for some or all Electric Distributors to reduce load across the PJM RTO Region in the manner they see fit to address the system conditions.”²²¹

By comparison, in response to a potential Interconnection Reliability Operating Limit Violation, as described in Mr. Pilonig’s Example 3, the deployment of an Interim Resource Adequacy Service Action in real-time may be more targeted. In Mr. Pilonig’s

²²⁰ Pilonig Aff. ¶ 52; *see id.* ¶¶ 48-55.

²²¹ Pilonig Aff. ¶ 43.

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Example 3, “the Dominion Zone is experiencing a transmission capacity scarcity event resulting from a potential IROL violation due to overloading of an IROL facility in West Virginia, e.g., AP South. In response, it makes little sense for PJM Dispatchers to curtail non-firm exports to the West or North of the PJM system. However, PJM may require curtailment of non-firm exports between PJM and areas to the South that are flowing power across the AP South IROL Reactive Interface to mediate the potential IROL violation.”²²² To the extent PJM Dispatchers determine it is necessary to issue an Interim Resource Adequacy Service Action in response to the potential IROL violation, it would likely be a more targeted Interim Resource Adequacy Service Action than the pro rata load reductions across multiple Electric Distributor zones/areas issued in Example 2. As Mr. Pilonig testifies, “[i]f load in a particular Electric Distributor zone/area is not negatively impacting transmission flows into the Dominion Zone, load reduction in that zone/area may not have any effect on the Dominion Zone.”²²³

3. *Electric Distributors must follow PJM directives to reduce megawatts of load in response to an Interim Resource Adequacy Service Action.*

When PJM issues an Interim Resource Adequacy Service Action, the applicable Electric Distributor will be sent an IRAS reduction MW quantity, which will be based on the IRAS quantity PJM determined for the Delivery Year, as described above in Part II.C.7. That is, an Interim Resource Adequacy Service Action will ***not*** be specific as to which New Large Loads would need to be reduced; rather, it will be based on the aggregate MW of

²²² Pilonig Aff. ¶¶ 48-55.

²²³ Pilonig Aff. ¶ 53.

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reduction available from the Eligible New Large Loads in the zone/area. The entities sent such directive will be expected, and required, to implement it. PJM proposes that Interim Resource Adequacy Service Action be defined as “an Operating Instruction, as defined by NERC.”²²⁴ As such, Electric Distributors and LSEs would need to follow it:

- Given that PJM is the Reliability Coordinator, NERC Reliability Standard IRO-001-4 R2 would require compliance with an Interim Resource Adequacy Service Action, as that standard provides that “[e]ach Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator’s Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.”²²⁵
- Similarly, given that PJM is the Transmission Operator, NERC Standard TOP-001-6 R1 would require compliance with an Interim Resource Adequacy Service Action, as that standard, provides that “[e]ach Transmission Operator shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions,” and R3 requires “[e]ach Balancing Authority, Generator Operator, and Distribution Provider shall comply with each Operating Instruction issued by its Transmission Operator(s), unless such action cannot be physically implemented.”²²⁶
- Finally, the Operating Agreement requires all Members and Market Participants, including Electric Distributors subject to unique obligations, to follow PJM Emergency procedures.²²⁷

²²⁴ In full, the proposed definition is: “‘Interim Resource Adequacy Service Action’ shall mean an Operating Instruction, as defined by NERC, issued from the Office of the Interconnection to reduce load prior to calling on Pre-Emergency Load Management Reductions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.” Proposed Tariff, Definitions – Interim Resource Adequacy Service Action.

²²⁵ *Standard IRO-001-4 Reliability Coordination - Responsibilities*, North American Electric Reliability Corporation (June 12, 2025), <https://www.nerc.com/globalassets/standards/reliability-standards/iro/iro-001-4.pdf> [<https://perma.cc/72GK-YZG3>].

²²⁶ *TOP-001-6 - Transmission Operations*, North American Electric Reliability Corporation (June 12, 2025), <https://www.nerc.com/globalassets/standards/reliability-standards/top/top-001-6.pdf> [<https://perma.cc/L3FQ-QBRN>].

²²⁷ See Operating Agreement, section 11.3.1(e) (Members shall “[e]comply with the requirements of the PJM Manuals and all directives of the Office of the Interconnection to take any action for the purpose of managing, alleviating or ending an Emergency.”); Operating Agreement, section 11.3.3(c) (Electric Distributors shall

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Accordingly, while PJM might not be able to directly reduce the loads of Eligible New Large Loads to the extent they are available to provide IRAS, PJM can direct others to do so with a high degree of confidence that such directives will be followed.

Given these requirements, it can be no surprise that today Electric Distributors select, consistent with their state programs, which loads to reduce in response to a PJM load reduction directive. Stated another way, PJM is not looking to change any existing approach. Currently, the manner in which an Electric Distributor reduces load is a function of their state-approved contracts and state-approved curtailment and load reduction plans.

4. *The IRAS load reduction framework is, at its core, a product of cooperative federalism that recognizes the significant role of the states in requiring New Large Loads to reduce their load to support reliability pursuant to IRAS.*

The proposed IRAS framework assigns an Eligible New Large Load Amount, which is measured in MW, to Electric Distributor zones/areas in a manner that respects the balance of authority between states, the Commission, and PJM.²²⁸ The framework

“[m]aintain or arrange for a portion of its connected load to be subject to control by . . . load-shedding devices at least equal to the levels established pursuant to the Reliability Assurance Agreement.”); Operating Agreement, section 11.3.3(e) (Electric Distributors shall “[s]hed connected load, share Generation Capacity Resources and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in Emergencies.”); Operating Agreement, Schedule 1, section 1.7.4(b) (“Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals.”); Operating Agreement, Schedule 1, section 1.7.4(g) (“Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.”); Operating Agreement, Schedule 1, section 1.7.11(a) (“The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis.”).

²²⁸ See, e.g., *New PJM Cos.*, 107 FERC ¶ 61,272, at P 22 (2004) (“In the event of a transmission emergency, PJM is only responsible for determining the location, quantity, and timing of any curtailment. PJM is not responsible for determining or directing the manner in which load is to be curtailed during an emergency.”).

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recognizes the role that states and/or RERRAs play in integrating New Large Loads and managing load reductions when necessary.²²⁹

- a. During an Interim Resource Adequacy Event, PJM will direct a MW quantity of load reduction to the relevant Electric Distributor zone(s)/area(s).

In a Delivery Year in which IRAS applies, PJM will identify, for each zone/area, the Eligible New Large Load Amounts, i.e., MW quantities that are eligible to be called upon to reduce load under IRAS. Directing an Electric Distributor, rather than a specific end-use customer, to reduce a quantity of load is in keeping with PJM's longstanding practice and reflects and respects the allocation of jurisdiction between the federal and state levels.²³⁰

More specifically, the Eligible New Large Load Amount assigned to each Electric Distributor will be derived from information and BYONC arrangements reported to PJM and recorded in the Large Load Registry. However, should PJM experience system conditions that require an Interim Resource Adequacy Service Action during a Delivery Year in which IRAS is in effect, PJM will instruct Electric Distributors to reduce load by a MW quantity equal to or less than the Electric Distributor's Eligible New Large Load Amount for that Delivery Year. PJM will *not* direct specific LSEs and/or specific customers of LSEs—including specific Large Loads—to reduce their load and/or switch

²²⁹ See, e.g., 52 Pa. Code § 57.52 (2026) ("Emergency load control and energy conservation by electric utilities."); 20 Va. Admin. Code § 5-300-20 (2026) ("Virginia electric energy emergency conservation plan.").

²³⁰ See, e.g., *New PJM Cos.*, 107 FERC ¶ 61,272 at P 21 ("When such emergency circumstances arise, PJM will inform the electric distribution company serving load of the quantity and location of load that must be shed, and the distributor, which directly serves the affected load, will effectuate the load-shedding.").

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to on-site backup resources. Those decisions would be worked out through revised state retail tariffs. PJM stands ready to assist states in developing those tariffs if they so desire.

Pursuant to the proposed framework, Electric Distributors will be responsible for “coordinat[ing] as appropriate, with the relevant state(s) or RERRA(s), individual Load Serving Entities, and customers served by the Load Serving Entities in its zone/area to support transparent, effective, and orderly deployment of Interim Resource Adequacy Service.”²³¹ Thus, under the IRAS framework, the specific retail customers that must reduce load consumption or switch to backup resources will be determined by the Electric Distributor and relevant LSEs in the zone/area, in coordination with the appropriate state and/or RERRA. Indeed, while PJM has proposed definitions of Large Load, New Large Load, and Eligible New Large Load that may be subject to IRAS, PJM simultaneously recognizes that states may each define “large loads” differently for purposes of their retail tariffs, particularly those governing load reduction protocols. Thus, while PJM will determine the quantity of MW that load in a zone/area will need to be reduced by to maintain system reliability in the PJM Region, states may determine—under their own laws, policies, and definition of what constitutes “large load”—which resources will be called on to reduce load.

- b. State efforts to develop load reduction programs reflect a cooperative federalism framework that is similar to that embedded in PJM’s proposal.

The division of authority and responsibility between states and PJM with respect to load reduction that is embedded in PJM’s proposed IRAS framework, is also reflected in

²³¹ Proposed Tariff, Attachment DD-4, section III(c).

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the ongoing efforts of the VA SCC and DCC, with other interested states, to jointly develop model state commission tariff language “establishing emergency load reduction programs designed to protect residential customers during the most severe reliability emergencies while preserving reliable system operations[,]” by no later than February 1, 2027, prior to the applicability of the IRAS framework.²³² According to the VA SCC, the model state commission tariff language would, *inter alia*:

- (1) Establish retail mechanisms authorizing utilities to curtail designated large commercial and industrial customers, or require the use of available on-site backup generation, once PJM has exhausted all other available reliability resources, including demand response, but before implementation of broad manual load shed; [and]
- (2) Define operational expectations, customer obligations, and utility implementation procedures associated with load reduction programs[.]²³³

The efforts of the VA SCC and DCC recognize the significant role of the states in determining which “designated large commercial and industrial customers” will be subject to load reduction programs, and the operational expectations and customer obligations associated with such programs. The efforts of the VA SCC and DCC also recognize the need to establish retail mechanisms authorizing utilities to curtail designated large commercial and industrial customers or require the use of available on-site backup generation. These mechanisms must allow PJM and utilities sufficient time to avoid the

²³² Letter of Chair of Virginia State Corporation Commission, Kelsey Bagot and President and CEO of Data Center Coalition, Josh Levi to Ms. Paula Conboy, Chair of PJM Board of Managers, and Mr. David Mills, President and CEO of PJM Interconnection, L.L.C., 2 (June 30, 2026), <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-written-comments---va-scc-and-data-center-coalition.pdf> [<https://perma.cc/S7C6-C86H>] (“VA SCC and DCC Letter”).

²³³ VA SCC and DCC Letter at 2.

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start of manual load shed well before declaration of EEA3. PJM stands ready to assist in those efforts and other related efforts and engagement.

c. The division of authority between PJM and the states and/or RERRAs is supported by relevant precedent.

PJM's proposed revisions are in line with recent Commission precedent. On October 23, 2025, the DOE ANOPR, which called on the Commission to consider "potential reforms to ensure the timely and orderly interconnection of large loads to the transmission system."²³⁴ The ANOPR further stated that "[e]ven if the large load seeking to interconnect to the transmission system is an end-use customer, the [ANOPR] does not exert jurisdiction over any retail sales to the large load."²³⁵ The Commission's subsequent Order Regarding Intent to Act on the ANOPR (Order on DOE ANOPR),²³⁶ found, *inter alia*, that large loads present an urgent need for reforms to ensure their timely, orderly, and non-discriminatory connection to the transmission system.²³⁷ Nevertheless, "the addition of and service to large loads" and the associated rates, terms, and conditions "implicate both federal and state interests."²³⁸ Accordingly, the Commission observed, "resolution of issues related to large load additions will require the involvement of both federal and state

²³⁴ DOE ANOPR at P 1 (citations omitted).

²³⁵ DOE ANOPR at P 15.

²³⁶ *Interconnection of Large Loads to the Interstate Transmission System*, 195 FERC ¶ 61,045 (2026) ("Order on DOE ANOPR").

²³⁷ Order on DOE ANOPR, 195 FERC ¶ 61,045 at P 2.

²³⁸ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 44; *see also* December 2025 Show Cause Order, 193 FERC ¶ 61,217 (Issues pertaining to large loads "implicate both federal and state interests, and their resolution will require the involvement of both federal and state actors, including the Commission, state public utility commissions, and other state and local entities."); *PJM Interconnection*, 195 FERC ¶ 61,197, *concur op.* (Commissioner Rosner) at P 2 ("[P]ublic utility commissioners, governors' offices, and state legislatures are all necessary partners in ensuring that energy infrastructure is built at the pace needed to stay ahead of demand and keep energy affordable and reliable for PJM customers.").

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actors, including the Commission, state public utility commissions, and other state and local entities.”²³⁹ Indeed, as the Commission’s Order on DOE ANOPR points out, in the last several years, the Commission has accepted proposed tariffs and agreements “related to large loads connecting to the transmission system . . . while rejecting those that exceeded the Commission’s jurisdiction or failed to reasonably allocate costs.”²⁴⁰ Likewise, an order to show cause issued by the Commission on February 20, 2025, on aspects of the co-location of large loads held that:

states retain exclusive jurisdiction over the terms of retail sales . . . including . . . how the costs of the wholesale sale and transmission of electricity assigned to a wholesale customer are allocated among that wholesale customer’s retail customers. Thus, while a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable, it is within a state’s exclusive jurisdiction to determine how those FERC-approved rates are collected among the relevant retail customers.²⁴¹

At bottom, “*exclusive jurisdiction*”²⁴² rests with the states to ensure that the appropriate retail customers, i.e., New Large Loads, including data centers—and not residential

²³⁹ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 44; *see also id.* at P 48 (Notably, the Commission has expressly “recognize[d] that states will continue to regulate: (1) the specific terms of retail sales to large load; (2) which entities may make retail sales within their borders; . . . and (3) any siting decisions and construction associated with the large load project.” (citations omitted)); December 2025 Show Cause Order, 193 FERC ¶ 61,217 at P 165 (Issues pertaining to large loads “implicate both federal and state interests, and their resolution will require the involvement of both federal and state actors, including the Commission, state public utility commissions, and other state and local entities.”); *PJM Interconnection*, 195 FERC ¶ 61,197, *concur op.* (Commissioner Rosner) at P 1 (“[P]ublic utility commissioners, governors’ offices, and state legislatures are all necessary partners in ensuring that energy infrastructure is built at the pace needed to stay ahead of demand and keep energy affordable and reliable for PJM customers.”).

²⁴⁰ Order on DOE ANOPR, 195 FERC ¶ 61,045 at P 2 (footnotes omitted).

²⁴¹ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115, at P 68, *order directing compliance*, December 2025 Show Cause Order, 193 FERC ¶ 61,217 (2025).

²⁴² *PJM Interconnection*, 190 FERC ¶ 61,115 at P 68 (emphasis added).

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customers or small industrial customers—are reduced when system conditions call for PJM to require load reductions according to IRAS.

The division of authority and responsibility between PJM and the PJM states is firmly rooted in the Supreme Court of the United States’ (“Supreme Court”) holding in *EPSA*.²⁴³ There, the Supreme Court held that the Commission’s regulation of demand response “addresses—and addresses only—transactions occurring on the wholesale market” and takes aim at “enhanc[ing] the wholesale, not retail, electricity market.”²⁴⁴ The Supreme Court accordingly held that the Commission’s rules for demand response withstood Electric Power Supply Association’s jurisdictional challenge by respecting the division of federal/state authority set forth in the FPA.²⁴⁵ Even though the FPA’s drafters could not have anticipated demand response, its regulation was nevertheless consistent with the division of jurisdictional authority contemplated by the FPA—in which the Commission, and thereby RTOs/ISOs, retain authority over wholesale transactions, while states regulate retail transactions.²⁴⁶ Likewise, the reforms in this filing address issues that the FPA’s drafters would have certainly considered science fiction—the resource adequacy impacts of New Large Loads, including data centers, driven primarily by exponential technological advancements in artificial intelligence.

²⁴³ *EPSA*, 577 U.S. at 260.

²⁴⁴ *EPSA*, 577 U.S. at 282, 287.

²⁴⁵ *EPSA*, 577 U.S. at 288-91.

²⁴⁶ See Matthew R. Christiansen, *FERC v. EPSA: Functionalism and the Electricity Industry of the Future*, 68 Stan. L. Rev. (Apr. 2016), <https://www.stanfordlawreview.org/online/ferc-v-epsa/> [<https://perma.cc/6QRP-KXET>] (citing *EPSA*, 577 U.S. at 265-68).

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In this case, PJM may issue directives to Electric Distributors to reduce load by a certain MW quantity during certain, limited emergency conditions. The Eligible New Large Load Amount attributable to each Electric Distributor zone/area will be guided by the Large Load Registry. Nevertheless, in recognition of the jurisdictional divide between PJM and the states and/or RERRAs, PJM will not direct reductions to specific New Large Loads pursuant to IRAS. Rather, PJM is leaving it to Electric Distributors, in coordination with the appropriate states and/or RERRAs, LSEs, and LSE customers to determine which loads should ultimately reduce subject to IRAS. Thus, the IRAS framework divides authority between PJM and the states in a manner consistent with the FPA's basic division of authority.

- d. The division of authority preserves the Commission's FPA sections 205 and 206 rights over the IRAS framework.

PJM's approach also finds support in the Commission's 2025 order accepting Midcontinent Independent System Operator, Inc.'s ("MISO") Revised Expedited Resource Addition Study ("ERAS") Proposal.²⁴⁷ In the ERAS order, the Commission found that RERRA participation in the ERAS process was permissible and not an improper delegation of federal authority to the states, as the participation of RERRA:

would be wholly pursuant to a Commission-jurisdictional process . . . proposed by MISO and approved by the Commission—not by state authorities—and under which a [Generator Interconnection Procedure] is on file with the Commission and any future revisions would be subject to Commission approval. Further, the ERAS process would remain subject to the Commission's authority pursuant to FPA sections 205 and 206. In contrast, in *Talen*, the Maryland Commission established a state program that

²⁴⁷ *Midcontinent Indep. Sys. Operator, Inc.*, Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing of Midcontinent Independent System Operator, Inc., Docket No. ER25-2454-000 (June 6, 2025).

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operated outside a Commission-jurisdictional process and “interfered” with the Commission’s authority to establish interstate wholesale rates.²⁴⁸

Similarly, PJM’s Tariff states that PJM will identify the MW quantity in a zone/area that will be eligible for load reduction under IRAS, but expressly places the responsibility on Electric Distributors to coordinate with relevant states and/or RERRAs, as well as LSEs and LSE customers, including Large Loads, to determine which retail customers will respond to PJM’s directive to reduce load.²⁴⁹ If approved by the Commission, the division of responsibility reflected in the Tariff would be on file and remain subject to the Commission’s authority pursuant to FPA sections 205 and 206.

As the Commission has previously observed, PJM’s resource adequacy framework requires that the Commission “recognize the traditional role of state and local entities in regulating resource adequacy” while also remaining “aware of [its] responsibilities under the FPA to ensure that adequate service is provided, and that wholesale rates are just and reasonable.”²⁵⁰ Thus, the Commission found that the appropriate course of action has been to “defer to state and local entities’ decisions when possible on resource adequacy matters, but in doing so . . . not shirk our congressionally-mandated responsibilities.”²⁵¹ The division of responsibilities embedded in the proposed IRAS framework is a balanced

²⁴⁸ *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064, at P 99 (2025) (distinguishing *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 163 (2016)), *order addressing arguments raised on reh’g*, 194 FERC ¶ 61,050 (2026).

²⁴⁹ Proposed Tariff, Attachment DD-4, section III(c).

²⁵⁰ *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 40 (2007) (requiring PJM to “allocate costs to data centers” in a manner similar to that as urged in the NEDC/PJM Governors’ Principles at 1), *aff’d sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 324 F.App’x 1 (D.C. Cir. 2009).

²⁵¹ *PJM Interconnection*, 119 FERC ¶ 61,318 at P 40.

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approach that reflects the well-considered divide between PJM and state/RERRA authorities over load reduction programs.

5. *Reducing New Large Loads before Pre-Emergency Load Management Reductions (EEA1) is not unduly discriminatory or preferential.*

The IRAS framework strikes a straightforward bargain. In Delivery Years when the influx of Eligible New Large Loads gives rise to a PJM Region-wide Reliability Requirement shortfall, New Large Loads without arrangements with new capacity will nevertheless be permitted to interconnect, and thus achieve “speed to power,” on the condition that their MW quantity of load is counted toward the MW potentially reduced during certain emergency conditions pursuant to IRAS. These Eligible New Large Load customers will be compensated under the IRAS framework to the extent that they reduce load pursuant to IRAS and do not waive compensation. The bargain is limited in scope and applies only to Eligible New Large Loads in years where their addition to the PJM system gives rise to an observed shortfall.²⁵² The LSEs serving these Eligible New Large Load customers, which receive NITS, will—like other NITS customers—have their transmission service curtailed *after* non-firm customers, but they may be asked to reduce load prior to other NITS customers in accordance with the Interim Resource Adequacy Service they may be asked to provide. At bottom, the IRAS framework recognizes that New Large Loads are not similarly situated to other loads, and reducing New Large Loads before Pre-Emergency Load Management Reductions (EEA1) is not unduly discriminatory or preferential. To that end, Members of Congress have expressed to PJM that “[i]t is not

²⁵² Proposed Tariff, Attachment DD-4, sections IV(b)(i)-(ii).

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unduly discriminatory to identify and manage demand from new data centers given their incomparably large energy demands, how quickly data centers can come online, and their unique potential to impact the reliability of the electric grid as a collective class and to increase rates for all other customers.”²⁵³

- a. New Large Loads are not similarly situated to other loads in the PJM Region, constitute a separate, new class of load, and are therefore appropriately subject to different treatment.

Requiring New Large Loads to reduce load before other NITS customers is not unduly discriminatory or preferential. In accordance with longstanding precedent, “[w]hether a rate or practice is unduly discriminatory depends on whether it provides different treatment to different classes of entities and turns on whether those classes of entities are similarly situated.”²⁵⁴ When differences in treatment “can be explained by some factor deemed acceptable to regulators (and the courts)”²⁵⁵ or “are predicated upon factual differences between customers,”²⁵⁶ they are justified and therefore not unduly discriminatory nor preferential.

²⁵³ Letter from the Members of Congress to David E. Mills, PJM Board Chair, PJM Interconnection, L.L.C., 4 (Nov. 5, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20251106-congressional-letter-re-cifp-lla.pdf> [https://perma.cc/ZKA9-Q5LZ].

²⁵⁴ *Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035, at P 318, *order on compliance, granting waiver request, addressing arguments raised on reh’g & setting aside prior order, in part*, 173 FERC ¶ 61,0061 (2020), *order on compliance & clarification*, 174 FERC ¶ 61,036, *order setting aside prior order, in part*, 174 FERC ¶ 61,109 (2021).

²⁵⁵ *Town of Norwood v. FERC*, 202 F.3d 392, 402 (1st Cir. 2000) (“[D]ifferential treatment does not necessarily amount to *undue* preference where the difference in treatment can be explained by some factor deemed acceptable by the regulators (and the courts).” (citation omitted)).

²⁵⁶ *Newark v. FERC*, 763 F.2d 533, 546 (3d Cir. 1985) (“[D]ifferences in rates are justified where they are predicated upon factual differences between customers.”).

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New Large Loads are not similarly situated to other loads in the PJM Region. According to the Commission, large loads constitute “a separate category of load.”²⁵⁷ In this case, the Commission has justified the differential treatment of New Large Loads, which is predicated on factual differences between customers. In fact, in recognition of this distinction, the Commission has required all RTOs/ISOs, including PJM, to define the term “large load” in their respective tariffs.²⁵⁸

In support of large loads being treated as a separate category of load, the Commission has highlighted the uniqueness of large loads, noting specifically that their integration “poses specific challenges to transmission system operation given their size, operational behavior, and unique potential to impact the transmission system.”²⁵⁹ Furthermore, the Commission has found that the records in the recent proceedings involving large loads “illustrate a host of urgent challenges associated with providing the transmission service needed to serve the ongoing influx of large loads while maintaining reliability and affordability. In particular, stakeholders have expressed concerns that large loads are not efficiently and appropriately integrated onto the transmission system; have identified a number of unique challenges that large load integration poses for the reliable operation of that system; and have debated how best to ensure that the rates, terms, and conditions of transmission service remain just and reasonable as more and more large loads

²⁵⁷ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 50; FPA section 215, 16 U.S.C. § 824o.

²⁵⁸ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58; *Midcontinent Indep. Sys. Operator, Inc.*, 195 FERC ¶ 61,212, at P 58 (2026); *Sw. Power Pool*, 195 FERC ¶ 61,213 at P 15 & n.54; *Cal. Indep. Sys. Operator Corp.*, 195 FERC ¶ 61,214, at P 57 (2026); *ISO New Eng. Inc.*, 195 FERC ¶ 61,215, at P 56 (2026); *N.Y. Indep. Sys. Operator, Inc.*, 195 FERC ¶ 61,216, at P 64 (2026).

²⁵⁹ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 58.

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are onboarded onto that system.”²⁶⁰ Recently, the Commission, in finding SPP’s CHILLS proposal for new large loads just and reasonable and not unduly discriminatory or preferential, the Commission observed that “SPP has shown that unprecedented growth in large loads in the SPP region presents significant and unique operational and planning challenges.”²⁶¹ Likewise, in the last two Delivery Years, since the influx of new large loads, consisting primarily of data centers, PJM has cleared short of its PJM Region Reliability Requirement in the face of exponential load growth. Challenges that are driven by the rapid addition of New Large Loads in PJM have called for PJM to respond accordingly with the slate of initiatives discussed above in Part I.C.

- b. IRAS is only applicable in Delivery Years when New Large Loads without arrangements with new capacity give rise to a PJM Region Reliability Requirement shortfall and provides opportunities for New Large Loads to avoid being subject to load reduction under IRAS.

The applicability of IRAS is limited and narrowly tailored. Where the Commission has found the treatment of large loads to be “tailored to the specific and unique nature of” of large loads, and “narrowly tailored to reflect the . . . unique characteristics” of such loads, the Commission has found that treatment just and reasonable and not unduly discriminatory or preferential.²⁶²

First, IRAS is limited to years in which the PJM Region experiences a resource adequacy shortfall. IRAS will only apply in Delivery Years where the amount of committed Capacity Resources is less than the Updated PJM Region Reliability

²⁶⁰ June 2026 Order to Show Cause, 195 FERC ¶ 61,211 at P 1.

²⁶¹ *Sw. Power Pool*, 195 FERC ¶ 61,196 at P 84.

²⁶² *Sw. Power Pool*, 195 FERC ¶ 61,196 at PP 85, 87.

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Requirement. Thus, it is only applicable when New Large Loads that have not brought their own capacity and have not been allocated sufficient RBP UCAP MW cause a PJM Region Reliability Requirement shortfall.

Second, New Large Loads may significantly mitigate the possibility of being called on to reduce load pursuant to IRAS by, for example, entering into arrangements with new capacity and working with their states to craft retail curtailment tariffs that may minimize disruption to data centers while protecting remaining native load.²⁶³ Thus, New Large Loads have the flexibility to engage in self-sufficiency to avoid or, at least, reduce the possibility of being called on to reduce load during an Interim Resource Adequacy Service Action.

Third, IRAS was developed to address the specific and unique issues caused by New Large Loads in the PJM Region, while also enabling New Large Loads to nevertheless be served by PJM.

Fourth, while PJM uses the Large Load Registry at the outset to establish Eligible New Large Load Amounts attributable to each zone/area in the PJM Region for each Delivery Year, PJM's reliance on the actual identities of those New Large Loads stops there. In other words, once PJM has determined, for the Delivery Year and based on the Large Load Registry, the MW quantity of resource adequacy shortfall in each zone/area based on New Large Loads in each zone/area that have not entered into arrangements with new capacity, PJM's operational directives will direct load reduction of certain MW quantities in certain zones/areas, not specific New Large Loads in those zones/areas.

²⁶³ See VA SCC and DCC Letter at 2.

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During real-time operations, PJM will direct Electric Distributors to reduce MW quantities of load in specific zones/areas under pre-emergency and emergency conditions, PJM will *not* direct specific New Large Loads to be reduced—albeit, states may, of course, establish and enforce their own retail load reduction programs. The IRAS framework does not single out New Large Loads for reduction because they are new or large. Rather, IRAS is focused on the reliability shortfall that is the result of the influx of these New Large Loads. IRAS is furthermore focused on responding accordingly with appropriate load reductions in the zones/areas with load to reduce. Under conditions of tightening supply and demand, it is a measured and well-considered response to permit the new demand causing the shortfall on the system to interconnect, subject to load reduction under limited emergency conditions, but receive compensation for that load reduction.²⁶⁴ While the IRAS framework gives rise to differences in the treatment of New Large Loads and other loads, the difference is meaningfully grounded in the fact that the current rapid growth in Large Loads are fundamentally different from the historical load growth, in both their inherent concentration of demand and the rapidity at which their cumulative demands have grown throughout PJM. These two factors are the cause of the recent reliability shortfall.²⁶⁵

²⁶⁴ See, e.g., *Tenaska Clear Creek Wind, LLC v. Sw. Power Pool, Inc.*, 183 FERC ¶ 61,043, at P 24 (2023) (finding that an “interconnection customer is differently situated from interconnection customers that have not caused the need for the network upgrades. This difference may justify that interconnection customer’s generating facility being subject to curtailment if it operates the generating facility prior to completion of the network upgrades when another is not so situated. Subjecting the interconnection customer that causes the need for upgrades in this manner ensures that the interconnection customer, bears the system-reliability burdens that flow from its decision to operate prior to completion of the required network upgrades.” (footnote omitted)).

²⁶⁵ See Independent Market Monitor for PJM, *Analysis of the 2027/2028 RPM Base Residual Auction Part A*, Monitoring Analytics, 2-3 (Jan. 5, 2026), https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf [<https://perma.cc/SM2E-KMTW>] (“The capacity shortfall in

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As such and, if they do not build, buy, or bring their own capacity, should be reduced, accordingly, should emergency conditions require it. Thus, the IRAS framework is not motivated by any desire to single out New Large Loads for reduction because of their size or vintage, but rather for the valid and legitimate reason that New Large Loads have led to periods of insufficient resource adequacy and should, justifiably, play a significant role in the remedy.²⁶⁶

c. Load reduction under Interim Resource Adequacy Service appropriately treats New Large Loads as NITS customers.

LSEs, which take service under NITS, serve their Eligible New Large Load customers. In the event of an Emergency Procedure IRAS Service Alert, Warning, and Action, the LSEs serving Eligible New Large Load customers—like other NITS customers in PJM—will only be called on to reduce load *after* non-firm transmission service products. As described above in Figure 2, PJM intends to amend its Manuals to include a new category of Emergency Procedure, in which PJM may require that a load reduction up to the quantity of Eligible New Large Load (Potential EEA1) in a zone/area *before* calling for Pre-Emergency Load Management Reductions (EEA1).

both the 2026/2027 and the 2027/2028 BRAs was a result of new data center load and forecast increases in existing data center load and the already existing demand from large data centers.”).

²⁶⁶ See, e.g., *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,114, at P 28 (2019) (finding that limiting participation in Peak Shaving Adjustment Program to resources governed by tariff or adopted by a RERRA not unduly discriminatory “because [Electric Distribution Companies (“EDCs”)] with RERRA-sponsored load curtailment programs are not similarly situated to EDCs without RERRA-sponsored load curtailment programs. . . . PJM has sufficiently demonstrated that the RERRA-sponsorship requirement is just and reasonable because it provides PJM with greater confidence in the durability of the peak-shaving program, as load reductions provided by RERRA-sponsored resources are more likely to continue over time, creating stability in load forecasts, which in turn will ensure efficient transmission planning and resource investment.”).

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PJM Manual 13 already requires resource types taking NITS to prevent a Manual Load Dump (at EEA3) by reducing load in a sequential order. Today, for example, sites registered in the PJM demand response program as a Demand Resource may be called on to reduce load in Pre-Emergency and Emergency Load Management Reduction Actions before firm exports are reduced in a Maximum Generation Emergency (EEA2). Nor is sequential load reduction or dispatch unique to PJM.²⁶⁷ As part of IRAS, PJM is simply proposing to add another category of resources that would precede the Demand Resources and DER Capacity Aggregation Resources called on to reduce load in Pre-Emergency and Emergency Load Management Reduction Actions.

E. Compensation for Load Reduction Under Interim Resource Adequacy Service

- 1. The proposed IRAS compensation approach respects and reflects the federal and state division of authority and responsibilities.*

As part of the proposed IRAS framework, Electric Distributors bear the responsibility to implement the compensation scheme for New Large Loads that provide the IRAS load reduction service. A representative class of these New Large Loads are signatories to the Ratepayer Protection Pledge that committed to “[c]ontribut[e] to [e]lectric and [c]ommunity [r]esilience” by “coordinat[ing] with grid operators to contribute to a more reliable grid.”²⁶⁸ IRAS reflects such coordination at a just and reasonable rate.

²⁶⁷ *Voltus, Inc.*, 190 FERC ¶ 61,008, at P 17 (2025) (noting that in MISO, “[Emergency Demand Resources] are dispatched after [Load Modifying Resources] in times of more acute need”).

²⁶⁸ Ratepayer Protection Pledge; July 2026 Ratepayer Protection Pledge Update (identifying 282 utilities, cooperatives, data centers, and 23 governors that joined the Ratepayer Protection Pledge, including 38 data centers).

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PJM is proposing a rate for IRAS that is equal to 50% of the Non-Performance Charge Rate. However, the wholesale IRAS rate is flexible and can be further reduced to less than 50% of the Non-Performance Charge Rate if the Eligible New Large Load accepts in its retail rate a sum less than 50% of the Non-Performance Charge Rate. As discussed below, PJM's proposal provides Electrical Distributors and states flexibility in the applicable IRAS rate for its territory, and affords the New Large Load the ability to waive compensation. Indeed, a rate of zero dollars for IRAS would apply where Eligible New Large Loads waive in their retail rates receipt of compensation for the provision of wholesale Interim Resource Adequacy Service—an outcome that would be consistent with the Ratepayer Protection Pledge signatories' commitment "to protect American consumers from price hikes due to data center energy and infrastructure requirements, and lower electricity costs for consumers in the long term."²⁶⁹

a. The proposed IRAS rate is just and reasonable.

PJM proposes to extend the rate applicable for Pre-Emergency Load Response non-performance (and conversely for bonus payments)—50% of the Non-Performance Charge Rate—as the maximum rate for IRAS performance.²⁷⁰ The Commission recently accepted this rate.²⁷¹ In that proceeding, PJM explained that the rate is appropriate for non-performance or under-performance by Pre-Emergency Load Response Program

²⁶⁹ Ratepayer Protection Pledge.

²⁷⁰ See proposed Tariff, Attachment DD-4, section X(a) ("The rate for the provision of Interim Resource Adequacy Service shall be 50% of the Non-Performance Charge Rate specified in Tariff, Attachment DD, section 10A(e), unless any Eligible New Large Load elects to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service as contemplated by Tariff, Attachment DD-4, section X(c).").

²⁷¹ *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,253 (2026).

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Participants as it reflects that the PJM system is at an earlier stage of emergency conditions, so the system conditions are not as severe, so the value of the load reduction, while still substantial, is also not as high as during a Performance Assessment Interval.²⁷² From a customer perspective, the non-performance rate appropriately reflects that load paid for capacity but did not get the benefit of the Pre-Emergency Load Response Program that PJM called upon at a time when the PJM system was in stressed system conditions.²⁷³ The monies collected in this instance were, generally speaking, allocated to demand resources that overperformed during such events (i.e., bonus payments), if applicable, with residual monies collected in certain situations reverting to LSEs that did not get the benefit of the load response service for which they paid.²⁷⁴

This recently accepted rate is a just and reasonable analog for the wholesale rate PJM proposes here for IRAS. As Mr. Pilog explains, IRAS would be called at the emergency conditions similar to when Pre-Emergency Load Response is called today.²⁷⁵ Indeed, Mr. Pilog explains that IRAS load reductions would now be introduced just before the Pre-Emergency Load Reduction Actions.²⁷⁶ Thus, similar to the Pre-Emergency Load Response Program, IRAS load is reduced at an earlier stage of emergency conditions and the 50% reduction on the Non-Performance Charge Rate also reflects that the current

²⁷² *PJM Interconnection, L.L.C.*, Proposal to Enhance Performance of Load Management Resources and Price Responsive Demand Providers During Non-Performance Assessment Interval Events of PJM Interconnection, L.L.C., Docket No. ER26-2319-000, Transmittal Letter at 11 (Apr. 27, 2026).

²⁷³ *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,253.

²⁷⁴ See *PJM Interconnection*, Proposal to Enhance Performance of Load Management Resources and Price Responsive Demand Providers During Non-Performance Assessment Interval Events of PJM Interconnection, L.L.C., Docket No. ER26-2319-000, Transmittal Letter at 17.

²⁷⁵ See Pilog Aff. ¶ 26.

²⁷⁶ See Pilog Aff. ¶ 26.

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Tariff-stated value of load reductions at these system conditions, i.e., where there is not sufficient available economic real-time supply “to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.”²⁷⁷

- b. Electric Distributors bear the responsibility, in conjunction with applicable state authorities and New Large Loads, to implement the compensation scheme.

The IRAS rate is compensation for a wholesale load reduction service, but the entities to be paid the rate and the loads to be charged to support such compensation must be determined at the state level consistent with the Electric Distributor’s state-approved load reduction plans and other state-approved programs, rates, and rules. As such, the IRAS rate is intended to be conjoined with retail rates and ultimately paid to Eligible New Large Loads that reflects a discount on capacity costs commensurate with the impact of Interim Resource Adequacy Service on addressing resource adequacy issues. The net result is a reduced capacity charge for Eligible New Large Loads, and thus a “practice . . . in which operators of wholesale markets pay electricity consumers for commitments *not* to use power at certain times” and thus “directly” affects wholesale capacity rates assessed.²⁷⁸

This compensation for load reduction under IRAS is not unduly discriminatory or preferential. As the Commission has recognized in recent landmark decisions (and as further discussed above), New Large Loads are a separate, unique class of load.²⁷⁹ PJM’s

²⁷⁷ Proposed Tariff, Attachment DD-4, section I(b).

²⁷⁸ See *EPSA*, 577 U.S. at 261, 265.

²⁷⁹ See, e.g., June 2026 Order to Show Cause, 195 FERC ¶ 61,211; December 2025 Show Cause Order, 193 FERC ¶ 61,217; *Sw. Power Pool*, 195 FERC ¶ 61,213; *Sw. Power Pool*, 195 FERC ¶ 61,196; *Sw. Power Pool*, 194 FERC ¶ 61,031.

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IRAS framework advances the Commission's policy set forth in those orders that the RTO/ISO tariff should be modified to support the integration of this class of load to the PJM Region. As a term of interconnection, for loads that have not brought their own capacity and cause unprecedented strain on the system, PJM is facilitating their interconnection subject to IRAS. New Large Loads may achieve the "speed to power" they desire and interconnect to the transmission system, but must either bring their own capacity or provide IRAS—a service for which there will be a compensation mechanism. In sum, New Large Loads are eligible to take this new service at a just and reasonable rate to the extent they elect to interconnect without BYONC to meet their resource adequacy needs. Alternatively, the proposal does not foreclose Eligible New Large Loads from foregoing any available wholesale IRAS compensation through appropriate engagement with Electric Distributors.²⁸⁰ This engagement would occur at the state level.²⁸¹ In these cases where IRAS credits in the retail rates are waived, the wholesale IRAS rate will be reduced to zero dollars, as allowed under the proposed language.²⁸² This is a just and reasonable rate. And importantly, including a zero-dollar rate aspect of the proposal is consistent with the Ratepayer Protection Pledge's tenet that New Large Loads "will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments wherever they

²⁸⁰ See proposed Tariff, Attachment DD-4, section X(a) ("If any Eligible New Large Load so elects to accept less than 50% of the Non-Performance Charge Rate or waives in its entirety receipt of compensation for the provision of wholesale Interim Resource Adequacy Service, the wholesale rate for the provision of Interim Resource Adequacy Service shall reflect the accepted sum less than 50% of the Non-Performance Charge Rate or if compensation is waived entirely, the rate shall be zero dollars.").

²⁸¹ PJM understands that in traditional, non-restructured states, the Electric Distributor also doubles as the LSE for the New Large Load, while in restructured states, the LSE may be an independent entity, not affiliated with the Electric Distributor.

²⁸² See proposed Tariff, Attachment DD-4, section X(a).

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build data centers. Importantly, they will pay these rates for the power and related infrastructure that are brought online to service their data centers, whether they use the electricity or not. . . . This will protect the American people from increased utility bills as a result of the development of these data centers.”²⁸³ PJM’s proposal also allows Eligible New Large Loads to agree upon a retail rate between 50% of the Non-Performance Charge Rate and zero dollars, to further facilitate implementation of the Ratepayer Protection Pledge and retail level arrangements.²⁸⁴

Under PJM’s proposal, how this wholesale rate is used to compensate for IRAS and how it is used to collect monies for such compensation will be left to the Electric Distributors that directed the specific load reductions to implement IRAS, consistent with their state-approved program, and that can identify the beneficiaries in their zone/area of such load reduction. In this way, how the compensation scheme will work in practice relies on application of state retail law.²⁸⁵ Whether a specific New Large Load may be entitled to compensation for provision of IRAS will be determined by state authorities under state law or RERRA as may be applicable. The program will be administered by the Electric Distributor in coordination with the relevant state authorities or RERRA. That said, PJM’s proposal imposes no obligation on any state to do anything. States are free to design retail rate regimes that facilitate the recovery and allocation of wholesale IRAS rates through generally applicable retail rate tariffs. Alternatively, if states decline to act generically, they could negotiate specific retail filed rates with affected entities. Further still, if states

²⁸³ Ratepayer Protection Pledge.

²⁸⁴ See proposed Tariff, Attachment DD-4, section X(a).

²⁸⁵ See proposed Tariff, Attachment DD-4, section X(b)(i).

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decline to act, Eligible New Large Loads could initiate regulatory proceedings to develop retail pathways to recover wholesale IRAS rates. Or, if states decline to act and Eligible New Large Loads decline to initiate regulatory proceedings to recover through retail rates the wholesale IRAS rate, they would effectively waive a right to compensation.²⁸⁶ Under PJM's proposal, the wholesale rate can flow into retail rates outside the PJM settlements realm.²⁸⁷ Alternatively, Electric Distributors, in consultation with their state regulators, can request PJM's support in implementing payment of the wholesale rate to Eligible New Large Loads and/or collection of charges to fund such compensation.²⁸⁸ Other potential flexibility might exist. The key takeaway is that PJM is not mandating any action at the retail or state level.

In sum, PJM's proposal imposes responsibilities on individual entities, and not the states themselves. While it enlists and invites state action through their jurisdictional retail processes, it does not mandate any state-specific action, nor does it require any specific terms and conditions on retail service. PJM's proposed federal filed rate facilitates and respects the handoff of responsibilities between federal wholesale rate development and state retail rate implementation. PJM's proposed framework avoids the potential for conflicts with state policy determinations and jurisdictional domains. PJM's proposal advances a framework that is consistent with the Commission's decision in the demand

²⁸⁶ Indeed, PJM is proposing to include in the compensation rules the following proviso: "Nothing in this Tariff, Attachment DD-4, section X shall interfere with any Eligible New Large Load's election to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service." Proposed Tariff, Attachment DD-4, section X(c).

²⁸⁷ Proposed Tariff, Attachment DD-4, section X(b)(i).

²⁸⁸ Proposed Tariff, Attachment DD-4, section X(b)(ii).

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response context to respect state law choices about whether and how to facilitate implementation of a wholesale paradigm, even one that indirectly affects retail rates when the wholesale rate flows back into retail rate structures.²⁸⁹ As in the demand response context, PJM’s proposed framework promotes durability and encourages federal-state communication and partnership without “plac[ing] an undue burden on state and local retail regulatory entities, or . . . rais[ing] new concerns regarding federal and state jurisdiction.”²⁹⁰

2. *The proposed billing indemnification language is just and reasonable.*

PJM is also proposing indemnification language as part of this compensation framework to make clear that neither PJM nor the PJM membership, generally, is financially responsible for any potential defaults that may arise in association with the billing of this compensation.²⁹¹ Thus, if a state-approved rate requires collection of the compensation for interruption under an IRAS Event from other LSEs, for example, and a LSE does not pay as required (whether billed directly by the Electric Distributor or by PJM upon request of the Electric Distributor), the default will not pass to the PJM membership. In the event the Electric Distributor requests that PJM facilitates the billing for an IRAS

²⁸⁹ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071, at P 154 (2008) (requiring “RTOs and ISOs to amend their market rules as necessary to permit an [aggregator of retail customers] to bid demand response on behalf of retail customers directly into the RTO’s or ISO’s organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate”); Order No. 719-B, 129 FERC ¶ 61,252 at P 5 (requiring “RTOs and ISOs to amend their market rules as necessary to permit an aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the RTO’s or ISO’s organized wholesale markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate”).

²⁹⁰ Order No. 719, 128 FERC ¶ 61,059 at P 155.

²⁹¹ See proposed Tariff, Attachment DD-4, section X(b)(iii).

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Event, such billing will be viewed as a bilateral transaction between the Electric Distributor and the other party and any default shall be assessed to the Electric Distributor. This language is just and reasonable because it minimizes risk to PJM and its members, and is consistent with other similar language the Commission has accepted in other parts of PJM's Governing Agreements.²⁹²

F. Consistent with the Ratepayer Protection Pledge, PJM Is Proposing to Exclude New Large Loads from the VRR Curve Until They Bring New Capacity.

PJM is proposing that, beginning with the 2029/2030 Delivery Year, PJM will exclude from the demand curve (i.e., the VRR Curve used in RPM Auctions) the MW of New Large Loads that have not entered into BYONC arrangements or do not have Allocated RBP UCAP MW, over and above the MW of New Large Loads that were included in the load forecast for the 2028/2029 Delivery Year.²⁹³

New Large Loads have, pursuant to the Ratepayer Protection Pledge, committed to “build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands” and “add more capacity that serves the broader public by increasing supply” in order to “advance[] self-sufficiency and protect[] Americans from higher

²⁹² See, e.g., Tariff, Attachment K-Appendix, section 5.2.2(d)(v) (“The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral agreement reported to the Office of the Interconnection under this” Tariff and Operating Agreement provision.).

²⁹³ PJM Board directs that “[i]ncremental [N]ew Large Loads relative to the forecast utilized for the 2028/2029 BRA . . . from the forecast used in future RPM auctions for the 2029/2030 Delivery Year and beyond unless and until there are new supply resources offered into an RPM auction in sufficient quantity to cover the [individual] new Large Load.” CIFP Framework for Service at 5.

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prices.”²⁹⁴ Thus, to the extent that New Large Loads come online, PJM expects that these loads will either “build, bring, or buy” new generation and capacity to serve their needs.

New Large Loads that have not entered into BYONC arrangements or do not have Allocated RBP UCAP MW will be excluded from the VRR Curve starting with the 2029/2030 Delivery Year regardless of whether PJM is experiencing a shortfall that triggers IRAS in the relevant Delivery Year. *Including* the quantity of New Large Loads that have not entered into BYONC arrangements or do not have Allocated RBP UCAP MW in the VRR Curve would fail to recognize that New Large Loads have committed to “build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands” and “add more capacity that serves the broader public by increasing supply.”²⁹⁵ *Excluding* the quantity of New Large Loads that have not entered into BYONC arrangements or do not have Allocated RBP UCAP MW from the VRR Curve, on the other hand, recognizes the commitment of New Large Loads to cover their own energy and

²⁹⁴ Ratepayer Protection Pledge; Ratepayer Protection Pledge Announcement; July 2026 Ratepayer Protection Pledge Update (identifying 282 utilities, cooperatives, data centers, and 23 governors that joined the Ratepayer Protection Pledge, including 38 data centers: Aligned Data Centers, LLC; Amazon.com, Inc.; Beale Infrastructure Group, LLC; CleanSpark LLC; Cloud HQ LLC; Cologix, Inc.; Compass Datacenters, LLC; Core Scientific, Inc.; CoreWeave, Inc.; Corscale, LLC; Crusoe Technologies LLC; CyrusOne, Inc.; DataBank Holdings, Ltd.; Digital Realty Trust, Inc.; EdgeConnex Inc.; EdgeCore Digital Infrastructure (d/b/a EdgeCore Internet Real Estate, LLC); Equinix, Inc.; Google (d/b/a Alphabet Inc.); Iron Mountain Incorporated; Meta Platforms, Inc.; Microsoft Corporation; Nebius Group N.V.; NTT Global Data Centers (d/b/a NTT DATA, Inc.); OpenAI, L.L.C.; Oracle Corporation; Oppidan Connect Data Centers (d/b/a Oppidan Investment Company); Prologis, Inc.; Quality Technology Services, LLC; Rowan Digital Infrastructure Pty. Ltd.; Skybox Datacenters, LLC; STACK Infrastructure, Inc.; Starwood Digital Ventures (d/b/a Starwood Capital Operations, LLC); Stream Data Centers, L.P.; Switch, Inc.; T5Data Centers, LLC; TA Realty LLC; Vantage Data Centers Management Company, LLC; and x.AI LLC).

²⁹⁵ Ratepayer Protection Pledge; Ratepayer Protection Pledge Announcement; July 2026 Ratepayer Protection Pledge Update.

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capacity needs to “advance[] self-sufficiency and protect[] Americans from higher prices.”²⁹⁶

Furthermore, in Delivery Years when there is a reliability shortfall and IRAS is triggered, to the extent these New Large Loads have not entered into BYONC arrangements or been Allocated RBP UCAP MW, their demand will be treated as Eligible New Large Load Amounts—that is, MW quantities that are eligible to provide IRAS by virtue of not having either entered into BYONC arrangements or having Allocated RBP UCAP MW. When an Eligible New Large Load interconnects subject to Interim Resource Adequacy Service, that New Large Load is, indeed, availing itself to an *interim* solution—which permits the Eligible New Large Load to obtain service while simultaneously permitting PJM to maintain grid reliability and resource adequacy—even before the New Large Loads’ BYONC arrangements are online and even if the New Large Loads are without Allocated RBP UCAP MW in that particular Delivery Year.

Once New Large Loads have met their commitment to build, bring, or buy capacity to meet their own needs—whether through BYONC or an assignment of RBP UCAP MW for the Delivery Year—the VRR Curve will incorporate the demand from the New Large Load, as well as the supply that it has committed to provide for purposes of meeting the demand it creates on the PJM system. A New Large Load that was previously eligible for IRAS because it previously had not entered into BYONC arrangements will begin to be

²⁹⁶ Ratepayer Protection Pledge; Ratepayer Protection Pledge Announcement; July 2026 Ratepayer Protection Pledge Update.

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included in the forecast for the same RPM Auction that its BYONC arrangement will be offered into the RPM Auction.²⁹⁷

1. *Excluding incremental New Large Load Amounts from the demand curve beginning with the 2029/2030 Delivery Year*

PJM is proposing two new Tariff definitions, “Excluded RTO New Large Load Amounts” and “Excluded Locational Deliverability Area (“LDA”) New Large Load Amounts” to mean the UCAP MW quantity of New Large Load that will not be reflected in the VRR Curve starting with the 2029/2030 Delivery Year. The definitions are as follows:

- “Excluded RTO New Large Load Amounts” shall mean, converted in UCAP terms by using the Forecast Pool Requirement and exclusive of any load in an FRR Service Area, [the sum of all New Large Loads across the PJM Region in the load forecast for the relevant Delivery Year] minus [New Large Loads across the PJM Region that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the RTO or (ii) assigned Allocated RBP UCAP MW in the RTO].²⁹⁸
- “Excluded LDA New Large Load Amounts” shall mean, converted in UCAP terms by estimating the impact on required imports to a Locational Deliverability Area and exclusive of any load in an FRR Service Area, [the sum of all New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast for the relevant Delivery Year] minus [New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the Locational Deliverability Area or (ii) assigned Allocated RBP UCAP MW in Locational Deliverability Area].²⁹⁹

²⁹⁷ Proposed Tariff, Attachment DD, section VII.

²⁹⁸ Proposed Tariff, Definitions – Excluded RTO New Large Load Amounts.

²⁹⁹ Proposed Tariff, Definitions – Excluded LDA New Large Load Amounts.

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To calculate the Excluded RTO New Large Load Amounts and the Excluded LDA New Large Load Amounts, first, begin with the sum of all New Large Loads across the PJM Region or in the relevant LDA in the load forecast for the relevant Delivery Year.

Second, subtract out the quantity of New Large Load in the load forecast for the 2028/2029 Delivery Year for either the RTO or relevant LDA. It is necessary to subtract this amount because the BRA for the 2028/2029 Delivery Year, which took place in July 2026, was the last auction conducted prior to this proposal. Because that auction predates this proposal, it relied on a load forecast that included all loads, including New Large Loads that had not entered into BYONC arrangements or have Allocated RBP UCAP MW, in the demand curve. As a result, the quantities of New Large Loads incorporated into the load forecast for the 2028/2029 Delivery Year are an appropriate reference point for measuring the incremental quantity of New Large Loads in the load forecast, beginning with the 2029/2030 Delivery Year.³⁰⁰ This results in the incremental MW value of New Large Load for the relevant Delivery Year.

Third, subtract the total MW quantity of New Large Load for the RTO or relevant LDA that is added on or after the 2029/2030 Delivery Year that has either entered into a BYONC arrangement or has Allocated RBP UCAP MW for that Delivery Year.

Fourth, as the above definitions reflect, Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts will be represented in UCAP terms. Thus, to determine the Excluded RTO New Large Load Amounts, the resulting value of the above

³⁰⁰ PJM proposes to maintain the inclusion of all New Large Loads in the demand curve for the remaining Incremental Auctions associated with the 2027/2028 and 2028/2029 Delivery Years to maintain consistency with those loads being included in the demand curve for the corresponding BRAs that have already been completed.

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steps will be converted into UCAP terms by multiplying the calculated amount by the Forecast Pool Requirement. Likewise, to determine the Excluded LDA New Large Load Amounts, the resulting value of the above steps will be converted into UCAP terms by multiplying the value by an estimated impact factor on required imports to an LDA.

Load in FRR Service Areas will continue to not be included in the VRR Curve, as FRR Entities already provide capacity for all load, including New Large Loads, in their FRR Service Areas.

The Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts, which are the UCAP MW that are not reflected in the RTO-wide VRR Curve and the VRR Curve for each LDA, respectively, should only reflect the incremental MW value of New Large Loads without BYONC or Allocated RBP UCAP MW in the PJM Region or the relevant LDA. As noted above, the quantity of New Large Loads will be reflected in the VRR Curve beginning with the same RPM Auction that the associated BYONC is offered for the first time.

The UCAP MW of New Large Loads that are not associated with qualifying BYONC or Allocated RBP UCAP MW are expected to build, bring, or buy their own generation and capacity to support their needs. During a Delivery Year in which IRAS is in effect, these quantities of New Large Loads that have not entered into BYONC arrangements or does not have Allocated RBP UCAP MW may, in the interim, be subject to load reduction pursuant to IRAS. Nevertheless, as proposed, the UCAP MW of New Large Loads without BYONC or Allocated RBP UCAP MW—whether or not subject to IRAS—will be excluded from the VRR Curve starting with the 2029/2030 Delivery Year.

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Therefore, in accordance with the Ratepayer Protection Pledge, New Large Loads would ultimately “add more capacity that serves the broader public by increasing supply.”³⁰¹

2. *New Large Loads with BYONC arrangements or Allocated RPB UCAP MW will be reflected in the demand curve.*

PJM’s proposed Tariff revisions provide that only the UCAP MW of New Large Loads without BYONC arrangements or Allocated RBP UCAP MW will be excluded from the demand curve, but New Large Loads are not expected to be indefinitely excluded. Rather, where New Large Loads have arrangements for capacity within the same RPM Auction, these quantities of New Large Loads will no longer be excluded from the VRR Curve. As explained above in Part II.C.3, BYONC resources with which New Large Load has entered into arrangements would be required to be offered in the RPM Auction as supply and as price takers.

Furthermore, the quantities of New Large Load would begin to be included in the VRR Curve in the same RPM Auction as the associated BYONC capacity. In this way, the impact of including such load in the demand curve is counterbalanced by the inclusion of a commensurate amount of additional Capacity Resources that are added to the supply curve. If a BYONC resource is offered into an RPM Auction *before* the quantity of New Large Load with which it has an arrangement is added to the demand curve, the RPM Auction would not reflect actual supply and demand fundamentals. Thus, to qualify as BYONC, the Capacity Resource must not have been offered and cleared in a prior RPM Auction where the load was not represented in the demand curve.³⁰² Notably, if a New

³⁰¹ Ratepayer Protection Pledge.

³⁰² Proposed Tariff, Attachment DD-4, section VI(a)(iii). Given that New Large Loads are included in the RPM Auctions through the 2028/2029 Delivery Year and eligible BYONC that previously cleared an RPM

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Large Load ramps up over time and arranges for a BYONC that is for the eventual full load, such BYONC would be allowed to be offered for the full amount into the first RPM Auction that the portion of the New Large Load will be included in the load forecast. This is appropriate because such BYONC is being brought to the system by the New Large Load and should not be partially offered when it is available to serve as capacity for the full accredited quantity.

On the supply side, the LSE that serves the New Large Load would report to PJM any BYONC arrangements with the New Large Loads in the zone/area at least 30 days prior to the deadline for PJM to post the planning parameters for the relevant RPM Auction.³⁰³ PJM will therefore have sufficient time to confirm that the reported Capacity Resources meets all of the BYONC eligibility requirements before including the quantity of New Large Load in the VRR Curve that will be posted as part of the planning parameters.

Furthermore, on the supply side, the BYONC resource, with which the New Large Load has entered into an arrangement must adhere to existing RPM Auction rules to ensure that the resource can be offered as a price taker in the relevant RPM Auction that the quantity of New Large Load would be included in demand curve. This includes, but is not limited to, meeting all the requirements to be offered as a Capacity Resource, submitting

Auction through the 2028/2029 Delivery Year was not on notice of this limitation, any eligible BYONC that is offered in RPM Auctions through the 2028/2029 Delivery Year can be procured by New Large Loads to avoid IRAS.

³⁰³ Proposed Tariff, Attachment DD-4, section VII(c).

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timely binding notice of intent to offer, and certifying that no buyer-side market power will be exercised in accordance with the existing rules and timelines.³⁰⁴

If an LSE does not timely report the New Large Load's arrangement with eligible BYONC to PJM by the specified deadline, then PJM would not include the quantity of New Large Load in the demand curve. This is because PJM will post the VRR Curve used for the relevant RPM Auction as part of the planning parameters so any submissions received after the deadline would not be timely incorporated into the demand curve.

To remove potential incentives for LSEs to not timely report New Large Loads in arrangements with BYONC resources, the quantity of those New Large Loads that have not been timely reported to PJM will continue to be subject to the IRAS in Delivery Years when IRAS is triggered, until the relevant LSEs have reported New Large Load arrangement with a BYONC Capacity Resource to PJM at least 30 days prior to the deadline for PJM to post the planning parameters³⁰⁵ for a subsequent RPM Auction.

3. *Each of the three points on the VRR Curve would be reduced by the Quantities of New Large Loads for the relevant Base Residual Auction.*

In addition to the two new definitions described above in Part II.F.1, PJM proposes to modify the existing rules in Tariff, Attachment DD, section 5.10(a) to specify that, for each of the three points on the VRR Curve, the Excluded RTO New Large Load Amounts would be deducted from the PJM Region Reliability Requirement, and the relevant

³⁰⁴ See generally Tariff, Attachment DD, section 5.3; Tariff, Attachment DD, section 5.14(h-2); RAA, Schedule 9.2; RAA, Schedule 10.

³⁰⁵ Proposed Tariff, Attachment DD-4, section VII(d). For the 2029/2030 Delivery Year, the arrangement must be reported 50 days prior to the commencement of the BRA or 30 days prior to the posting of the planning parameters for the Scheduled Incremental Auctions. See Proposed Tariff, Attachment DD-4, section VII(c).

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Excluded LDA New Large Load Amounts would be deducted from the respective LDA Reliability Requirements before being multiplied by the relevant existing percentages.³⁰⁶

Given that the Commission accepted the extension of the price collar through the 2029/2030 Delivery Year, the proposed Tariff revisions maintain the distinctions between the VRR Curve for the 2029/2030 Delivery Year and the VRR Curve associated with the subsequent Delivery Years. Similarly, the respective points on the LDA VRR Curves would be reduced by the relevant Excluded LDA New Large Load Amounts.³⁰⁷

4. *The Incremental Auctions will reflect adjustments of capacity previously committed, including any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts.*

As with the BRAs, PJM would similarly exclude Eligible New Large Load Amounts from the Demand Curve for Scheduled Incremental Auctions. To do this, PJM proposes to modify the definition of Updated VRR Curve to account for the Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts.³⁰⁸ This definition will then be incorporated by reference in the existing definitions of Updated VRR Curve Increment and Updated VRR Curve Decrement, which are used in the optimization algorithm for clearing the Scheduled Incremental Auctions.³⁰⁹

³⁰⁶ Proposed Tariff, Attachment DD, section 5.10(a)(i).

³⁰⁷ Proposed Tariff, Attachment DD, section 5.10(a)(ii)(C).

³⁰⁸ Proposed Tariff, Definitions – Updated VRR Curve (“‘Updated VRR Curve’ shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any changes in the Reliability Requirement, Excluded RTO New Large Load Amounts, and/or Excluded LDA New Large Load Amounts from the Base Residual Auction to the relevant Incremental Auction.”).

³⁰⁹ See Tariff, Attachment DD, section 5.12(b).

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PJM also proposes to modify the existing rules in Tariff, Attachment DD, section 5.4 to specify that each LDA Reliability Requirement will be updated to reflect adjustments to the Excluded LDA New Large Load Amounts. Similarly, PJM is proposing to modify the existing rules in Tariff, Attachment DD, section 5.4 to specify that each LDA Reliability Requirement will be updated to reflect adjustments to the Excluded LDA New Large Load Amounts. These revisions conform the treatment of Excluded LDA New Large Load Amounts and Excluded RTO New Large Load Amounts in Incremental Auctions to their treatment in BRAs, starting with the 2029/2030 Delivery Year.

5. *PJM will maintain transparency by posting the Variable Resource Requirement Curve in advance of the RPM Auctions.*

Consistent with the existing practice of posting VRR Curves as part of the broader planning parameters that are posted as part of the pre-auction process, PJM proposes to memorialize the posting requirement by specifying that the VRR Curves will be “posted on the same timeline with the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement.”³¹⁰ Since the VRR Curve for the 2029/2030 Delivery Year will be posted as part of the planning parameters under the existing Tariff rules by August 31, 2026, PJM makes clear in the proposed Tariff that an Updated VRR Curve for the 2029/2030 BRA will be posted one month prior to the commencement of the RPM Auction.

³¹⁰ Proposed Tariff, Attachment DD, section 5.10(a)(vi)(B). This deadline would typically be February 1 prior to the conduct of a BRA when it is conducted on a normal three-year schedule. However, until the 2030/2031 BRA, the RPM Auctions are still on a compressed auction schedule with the deadline for posting the planning parameters subject to a Commission waiver order. See *PJM Interconnection, L.L.C.*, 189 FERC ¶ 61,105 (2024).

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Posting an Updated VRR Curve for the 2029/2030 BRA is entirely distinguishable from the underlying facts in the United States Court of Appeals for the Third Circuit's order finding that updating the LDA Reliability Requirement after the auction commenced was barred by the filed-rate doctrine.³¹¹ Because PJM will post the Updated VRR Curve for the 2029/2030 BRA 30 days *before* the auction commences and binding offers are submitted by Capacity Market Sellers, no legal consequences attach after PJM posts the initial VRR Curve on August 31, 2026, especially as this filing provides notice that the yet-to-be posted VRR Curve is subject to change in accordance with the proposal set forth in this filing.

Finally, in addition to specifying that the VRR Curve will be posted prior to the auction, PJM also proposes to specify that the Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts used in establishing the VRR Curve will be included in the posting requirement beginning with the 2029/2030 BRA.³¹²

³¹¹ *PJM Power Providers Grp. v. FERC*, 96 F.4th 390, 400 (3d Cir. 2024).

³¹² Proposed Tariff, Attachment DD, section 5.11(a)(iii).

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III. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, DC 20005
(202) 423-4743
craig.glazer@pjm.com

Ryan J. Collins
Vivian W. Chum
Wright & Talisman, P.C.
1200 G Street, NW, Suite 600
Washington, DC 20005
(202) 393-1200
collins@wrightlaw.com
chum@wrightlaw.com

Mark J. Stanisz
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-8800
mark.stanisz@pjm.com

IV. REQUESTED EFFECTIVE DATE AND CONSENT TO MODIFICATION OR SEVERANCE OF ISSUES

PJM requests that the Commission issue an order on this filing and make the enclosed proposed Tariff and RAA revisions effective by no later than October 12, 2026, 2026, which is 60 days after the date of this filing, and to make the Large Load Registry rules effective October 12, 2026, which is 60 days from the date of filing. Such an effective date will allow PJM to start building the Large Load Registry and accept reports of arrangements between New Large Loads and BYONC in time to expeditiously develop and post a new VRR Curve with the New Load Loads removed to the extent they do not have BYONC arrangements. An October 12, 2026 effective date will not affect when PJM will call an Interim Resource Adequacy Service Action. As the enclosed revisions make clear, IRAS starts being available with the 2027/2028 Delivery Year, i.e., June 1, 2027.

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Further, allowing the revisions to be effective on the date requested, and allowing IRAS to commence June 1, 2027, would enable the states and other interested entities to put in place the appropriate state-level tools to complement and implement IRAS. As discussed, PJM understands that some states have begun proceedings to evaluate how to best facilitate coordination with PJM on implementing IRAS. PJM welcomes all such efforts.

In addition, as noted above, however, to facilitate Commission approval and smooth implementation of the IRAS on June 1, 2027, PJM consents to the Commission's exercise of authority to modify and/or sever the proposed Tariff and RAA language, as needed and permitted under the FPA and *NRG Power Marketing*,³¹³ where such modification is consistent with PJM's overarching objectives in this filing.³¹⁴ In addition, PJM provides the following requests and observations:

First, should the Commission exercise its authority to modify the proposed Tariff language herein pursuant to the FPA and *NRG Power Marketing*, PJM respectfully requests that the Commission expressly prescribe the revised rate or rule in its order. Prescriptive revised language from the Commission would provide the "necessary predictability" to

³¹³ *NRG Power Mktg.*, 862 F.3d at 108. As the Commission has repeatedly stated, "[t]he United States Court of Appeals for the District of Columbia Circuit has held that, in certain circumstances, the Commission has 'authority to propose modifications to a utility's [FPA section 205] proposal if the utility consents to the modifications.'" *N.Y. Indep. Sys. Operator*, 188 FERC ¶ 61,051 at P 22 n.36 (second alteration in original) (citing *NRG Power Mktg.*, 862 F.3d at 114-15); see *Midcontinent Indep. Sys. Operator*, 180 FERC ¶ 61,141 at P 26 n.29 (same); *ISO New England*, 175 FERC ¶ 61,172 at P 16 n.20 (same).

³¹⁴ PJM is not, for example, suggesting that the Commission may modify or sever provisions of its proposal to result in an "entirely different rate design." *NRG Power Mktg.*, 862 F.3d at 115 ("Our decisions in *City of Winnfield* and *Western Resources* indicate that Section 205 does not allow FERC to suggest modifications that result in an 'entirely different rate design' than the utility's original proposal or the utility's prior rate scheme."); see also *id.* at 116 (holding that the Commission's modifications resulted in an entirely different rate design where Commission's modifications: (1) replaced PJM's proposal to permit exemption where generators demonstrate on a case-by-case basis that their costs fell below the price floor with one in which generators can claim exemptions even if they cannot demonstrate that their price falls below the floor; (2) undid the compromise between LSEs and Generators and thus "eviscerated the terms of the bargain").

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allow PJM to implement such changes to elements of the Large Load Registry or IRAS in a timely manner.³¹⁵ PJM's submittal of any compliance filing implementing such modifications would constitute PJM's consent and acceptance of the Commission's modifications.

Second, PJM observes that the facts underlying the PJM proposal at issue in *NRG Power Marketing* are distinguishable from the facts here. In *NRG Power Marketing*, the FPA section 205 filing with the Commission was one in which "PJM asked the Commission 'to view this filing not as a list of discrete Tariff changes, but . . . a hard-fought compromise package, and to approve it as such.'"³¹⁶ By contrast, the proposal put forth here is not a stakeholder compromise package. Unlike *NRG Power Marketing*, there is no danger of undoing the compromise between LSEs and Generators and thus "eviscerat[ing] the terms of the bargain."³¹⁷ Rather, this filing is the product of an RBP proposal that was independently endorsed by the PJM Board following the CIPF stakeholder process. Moreover, through this pre-emptive grant of authority pursuant to

³¹⁵ *PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,137, at P 110 (2021) (first quoting *Aera Energy LLC v. FERC*, 789 F.3d 184, 190-92 (D.C. Cir. 2015) ("affirming the Commission, finding 'FERC's conditional acceptance . . . simply required Kern River to substitute one number for another when allocating costs to the rolled-in shippers. . . . Because this mechanical change gave Kern River no discretion to adjust its rate models, FERC provided sufficient notice to ratepayers'"); and then quoting *Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985) ("vacating when the 'effective date of an order set[] forth no more than the basic principles pursuant to which the new rates are to be calculated'") (alteration in original)). As the Commission elaborated further in *PJM Interconnection*, mere "direction" without "sufficient detail on each element [of the replacement rate] that [customers/market participants] could determine when their transactions would be subject to [the new rule]," would mean that implementation of the compliance directive prior Commission approval would violate the filed rate doctrine. *Id.* (quoting *Elec. Dist. No. 1*, 774 F.2d at 493 ("[P]urchasers of electricity cannot plan their activities unless they know the cost of what they are receiving, 'providing the necessary predictability is the whole purpose of the well-established filed rate doctrine.'" (citing *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 (1981)))).

³¹⁶ *NRG Power Mktg.*, 862 F.3d at 113 (citation omitted).

³¹⁷ *NRG Power Mktg.*, 862 F.3d at 116.

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which the Commission may sever and modify each element of the proposal, stakeholders are on notice of potential changes to the proposal as filed, and will have the opportunity to comment as they feel necessary and appropriate.

Third, although PJM consents to make each element of the proposed revisions to the Tariff and RAA severable, PJM has demonstrated that each element of its proposal is just and reasonable. Notwithstanding PJM's grant of authority to sever, PJM urges the Commission to accept all revisions as proposed so that the elements of the Large Load Registry can commence on October 12, 2026; would allow PJM to expeditiously post an Updated VRR Curve for the December 2029/2030 BRA; and IRAS can begin June 1, 2027.

To the extent the Commission does sever and modify any element, the Commission should recognize that, while the RAA and Tariff revisions together advance a means for addressing the resource adequacy issues resulting from new large loads interconnecting to the transmission system faster than new capacity is being placed in service. The elements of this proposal were developed together and designed to work in lockstep and provide complementary pieces to a multi-prong approach to incent New Large Loads to bring their own capacity to meet their resource adequacy needs and avoid imposing costs on ratepayers. Indeed, the VRR Curve changes are predicated on the BYONC proposed as part of the IRAS framework. Conversely, the general obligation that Load Serving Entities bring new capacity in an amount that equals or exceeds its New Large Loads' peak load and Large Load Registry are each discrete from the other elements of this filing and would provide an independent value of informing PJM's operations, planning, and load forecasting activities.

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Finally, PJM continues to discuss with states and other stakeholders how to address these issues, particularly the federal-state handoff of responsibilities. To that end, PJM may, at the behest of the states, host workshops with states and other stakeholders, which may result in amendments to the proposals submitted herein and, if necessary, additional time for comments and consideration as may be necessary or appropriate.

V. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Revisions to the PJM Tariff and Resource Adequacy Agreement (in redlined and non-redlined format (as Attachments A and B, respectively) and in electronic tariff filing format as required by Order No. 714);³¹⁸ and
3. Affidavit of Christopher Pulong on Behalf of PJM Interconnection, L.L.C. as Attachment C.

VI. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,³¹⁹ PJM will post a copy of this filing to the Commission filings section of its internet site, located at the following link: <https://www.pjm.com/library/filing-order.aspx> with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region³²⁰ alerting them that this filing

³¹⁸ *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

³¹⁹ See 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

³²⁰ PJM already maintains, updates, and regularly uses e-mail lists for all PJM members and affected state commissions.

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has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

VII. CONCLUSION

Based on the foregoing, PJM requests that the Commission accept the enclosed proposed Tariff and RAA revisions by October 12, 2026, effective as requested.

Respectfully submitted,

/s/ Ryan J. Collins

Ryan J. Collins

Vivian W. Chum

Wright & Talisman, P.C.

1200 G Street, NW, Suite 600

Washington, DC 20005

(202) 393-1200

collins@wrightlaw.com

chum@wrightlaw.com

Craig Glazer

Vice President–Federal Government Policy

PJM Interconnection, L.L.C.

1200 G Street, NW, Suite 600

Washington, DC 20005

(202) 423-4743

craig.glazer@pjm.com

Mark J. Stanisz

Associate General Counsel

PJM Interconnection, L.L.C.

2750 Monroe Blvd.

Audubon, PA 19403

(610) 666-8800

mark.stanisz@pjm.com

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Attachment A

Revisions to the PJM Open Access Transmission Tariff and Resource Adequacy Agreement

(Marked/Redline Format)

Definitions – A - B**30-minute Reserve:**

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Allocated RBP UCAP MW:

“Allocated RBP UCAP MW” shall mean the RBP UCAP MW allocated to a New Large Load in accordance with Tariff, Attachment DD-4, section IX.

Ambient-Adjusted Rating:

“Ambient-Adjusted Rating” (AAR) shall mean a Transmission Facility Rating that:

- (a) Applies to a time period of not greater than one hour.
- (b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
- (c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
- (d) Is evaluated at least each hour, if not more frequently.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network

Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance

Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or

such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

“Batch Load Economic Load Response Participant Resource” shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided,

however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall mean megawatts of Unforced Capacity that meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI. Megawatts of Unforced Capacity that have been previously included in an FRR Capacity Plan prior to the 2027/2028 Delivery Year do not qualify as BYONC. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then BYONC that has been included previously in an FRR Capacity Plan prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI do not qualify as BYONC.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – E - F**Economic-based Enhancement or Expansion:**

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Load Response Regulation Only Participant:

“Economic Load Response Regulation Only Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, and is only eligible to participate in the PJM Regulation market.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORD:

“EFORD” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Eligible New Large Loads:

“Eligible New Large Loads” shall mean a New Large Load eligible to provide Interim Resource Adequacy Service in accordance with Tariff, Attachment DD-4, section V.

Eligible New Large Load Amount:

“Eligible New Large Load Amount” shall mean the total megawatt value of load an Eligible New Large Load may be required to make available for Interim Resource Adequacy Service in an Electric Distributor zone/area.

Emergency Action:

“Emergency Action” shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when

dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has an operational limitation due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Excluded LDA New Large Load Amounts:

“Excluded LDA New Large Load Amounts” shall mean, converted in UCAP terms by estimating the impact on required imports to a Locational Deliverability Area and exclusive of any load in

an FRR Service Area, [the sum of all New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast for the relevant Delivery Year] minus [New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the Locational Deliverability Area or (ii) assigned Allocated RBP UCAP MW in Locational Deliverability Area].

Excluded RTO New Large Load Amounts

“Excluded RTO New Large Load Amounts” shall mean, converted in UCAP terms by using the Forecast Pool Requirement and exclusive of any load in an FRR Service Area, [the sum of all New Large Loads across the PJM Region in the load forecast for the relevant Delivery Year] minus [New Large Loads across the PJM Region that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the RTO or (ii) assigned Allocated RBP UCAP MW in the RTO].

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time

periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an

invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account.

Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – I – J - K**IDR Transfer Agreement:**

“IDR Transfer Agreement” shall mean an agreement to transfer, subject to the terms of Tariff, Part VI, section 237, Incremental Deliverability Rights to a party for the purpose of eliminating or reducing the need for Local or Network Upgrades that would otherwise have been the responsibility of the party receiving such rights.

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall have the same meaning provided in the Operating Agreement.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Incidental Expenses:

“Incidental Expenses” shall mean those expenses incidental to the performance of construction pursuant to an Interconnection Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Interconnected Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Customer Facility and for the Interconnection Facilities.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction) shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed

circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Incremental Auction Revenue Rights:

“Incremental Auction Revenue Rights” shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Available Transfer Capability Revenue Rights:

“Incremental Available Transfer Capability Revenue Rights” shall mean the rights to revenues that are derived from incremental Available Transfer Capability created by the addition of Merchant Transmission Facilities or of one or more Customer-Funded Upgrades.

Incremental Capacity Transfer Right:

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

“Incremental Deliverability Rights” or “IDRs” shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Interconnection Customer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Incremental Rights-Eligible Required Transmission Enhancements:

“Incremental Rights-Eligible Required Transmission Enhancements” shall mean Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Tariff, Schedule 12) and meet one of the following criteria: (1) cost responsibility is assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Independent Auditor:

“Independent Auditor” shall mean an external accountant or external accounting firm who is not an employee of, not otherwise related to, not obligated to, has no interest in, and is independent in the performance of professional services for, the entity he/she/it is auditing, its management and/or its owners.

Initial Operation:

“Initial Operation” shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Tariff, Attachment O-Appendix 2, section 1.4 (an Interconnection Service Agreement).

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Tariff, Attachment K-Appendix, section 2.2.

Interconnected Entity:

“Interconnected Entity” shall mean either the Interconnection Customer or the Interconnected Transmission Owner; Interconnected Entities shall mean both of them.

Interconnected Transmission Owner:

“Interconnected Transmission Owner” shall mean the Transmission Owner to whose transmission facilities or distribution facilities Customer Interconnection Facilities are, or as the case may be, a Customer Facility is, being directly connected. When used in an Interconnection

Construction Service Agreement, the term may refer to a Transmission Owner whose facilities must be upgraded pursuant to the Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

Interconnection Construction Service Agreement:

“Interconnection Construction Service Agreement” shall mean the agreement entered into by an Interconnection Customer, Interconnected Transmission Owner and the Transmission Provider pursuant to Tariff, Part VI, Subpart B and in the form set forth in Tariff, Attachment P, relating to construction of Attachment Facilities, Network Upgrades, and/or Local Upgrades and coordination of the construction and interconnection of an associated Customer Facility. A separate Interconnection Construction Service Agreement will be executed with each Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

“Interconnection Customer” shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

“Interconnection Facilities” shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

“Interconnection Feasibility Study” shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

“Interconnection Party” shall mean a Transmission Provider, Interconnection Customer, or the Interconnected Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

“Interconnection Request” shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

“Interconnection Service” shall mean the physical and electrical interconnection of the Customer Facility with the Transmission System pursuant to the terms of Tariff, Part IV and Tariff, Part VI and the Interconnection Service Agreement entered into pursuant thereto by Interconnection Customer, the Interconnected Transmission Owner and Transmission Provider.

Interconnection Service Agreement:

“Interconnection Service Agreement” shall mean an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Tariff, Part IV and Tariff, Part VI.

Interconnection Studies:

“Interconnection Studies” shall mean the Interconnection Feasibility Study, the System Impact Study, and the Facilities Study described in Tariff, Part IV and Tariff, Part VI.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Interim Resource Adequacy Service:

“Interim Resource Adequacy Service” shall mean a load reduction service through which New Large Loads reduce load as directed by the applicable Electric Distributor in response to an Interim Resource Adequacy Service Action requested by the Office of the Interconnection. Such reductions in load may be eligible for compensation pursuant to Attachment DD-4, section X.

Interim Resource Adequacy Service Action:

“Interim Resource Adequacy Service Action” shall mean an Operating Instruction, as defined by NERC, issued from the Office of the Interconnection to reduce load prior to calling on Pre-Emergency Load Management Reductions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.

Intermittent Resource:

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

Internal Credit Score:

“Internal Credit Score” shall mean a composite numerical score determined by PJMSettlement using quantitative and qualitative metrics to estimate various predictors of a credit event happening to a Market Participant that may trigger a credit event.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

Interruption:

“Interruption” shall mean a reduction in non-firm transmission service due to economic reasons pursuant to Tariff, Part II, section 14.7.

IROL Critical Resource:

“IROL Critical Resource” shall mean a generation resource that the Office of the Interconnection designates, pursuant to NERC Reliability Standards, as having an interconnection reliability operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.

Jointly Owned Cross-Subsidized Capacity Resource:

“Jointly Owned Cross-Subsidized Capacity Resource” shall mean a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Definitions – L – M – N**Large Load:**

“Large Load” shall have the meaning provided in the Reliability Assurance Agreement.

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model

employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with

preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD, section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum State of Charge:

“Maximum State of Charge” shall mean the maximum State of Charge that should not be exceeded, measured in units of megawatt-hours.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker

opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

Minimum State of Charge:

“Minimum State of Charge” shall mean the minimum State of Charge that should be maintained in units of megawatt-hours.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

“Mixed Technology Facility” shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

“Near-Term Transmission Service” shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. “Near-Term Transmission Service” includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a

Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New Large Load:

“New Large Load” shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1, 2027, or (b) incremental load in-service after June 1, 2027, that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then New Large Load shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met or (b) incremental load in-service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Curtailment Charge:

“Non-Curtailment Charge” shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

“Non-PAI Event” shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions – T – U - V**Tangible Net Worth:**

“Tangible Net Worth” shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

“Third Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the

Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

“Trade Reference” shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Facility Rating:

“Transmission Facility Rating” shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment.

Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

“Transmission Service” shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

“Transmission Service Request” shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

“Transmission System” shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

“Unconstrained LDA Group” shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

“Unforced Capacity” shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any changes in the Reliability Requirement, Excluded RTO New Large Load Amounts, and/or Excluded LDA New Large Load Amounts from the Base Residual Auction to such-the-relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile

For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

“Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

“Virtual Transactions Net Activity” shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, the Base Residual Auction for the 2026/2027 Delivery Year shall be conducted in July 2025; the Base Residual Auction for the 2027/2028 Delivery Year shall be conducted in December 2025; the Base Residual Auction for the 2028/2029 Delivery Year shall be conducted in June 2026; and the Base Residual Auction for the 2029/2030 Delivery Year shall be conducted in December 2026. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for the 2025/2026 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2025; for the 2026/2027 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2026; for the 2027/2028 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which will commence on July 2026 and February 2027, respectively; for the 2028/2029 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which shall commence on July 2027 and February 2028, respectively.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement or the LDA Reliability Requirement (inclusive of any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement;

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained; or

iii) regarding a Generation Capacity Resource that is subject to Tariff, Attachment DD, section 5.3(b), (a) the Office of Interconnection determines prior to the Third Incremental Auction that such resource will not meet the criteria set forth in Tariff, Attachment DD, section 5.3(b)(i) for the relevant Delivery Year or (b) such resource's final Accredited UCAP is less than the UCAP amount considered in the Base Residual Auction in which the resource was deemed to be the subject of a Sell Offer.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the

PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, decrease in Accredited UCAP Factor, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement or Locational Deliverability Area Reliability Requirement for such Delivery Year. For any auction, the Updated Forecast Peak Load applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis.
- For the 2025/2026 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 98.9%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.6%]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.8%].
- For the 2026/2027 Delivery Year and 2027/2028 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
- For the 2028/2029 ~~and 2029/2030~~ Delivery Years, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by

(the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

- For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.0%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
- For the 2029/2030 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%};
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%.

- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
- For the 2030/2031 Delivery Year and for subsequent Delivery Years, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%];
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%].
- ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:
 - A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or
 - B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or
 - C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year, the Eastern Mid-Atlantic Region

(“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), and Mid-Atlantic Region (“MAR”) LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, beginning with the 2029/2030 Delivery Year, the points on the LDA Variable Resource Requirement Curves will be reduced by the relevant Excluded LDA New Large Load Amounts. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For Delivery Years up to and including the 2027/2028 Delivery Year for each such LDA, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA.

For the 2028/2029 Delivery Year and for subsequent Delivery Years for each such LDA, the Office of the Interconnection shall determine the applicable Cost of New Entry and Net Energy and Ancillary Services Revenue Offset value for each LDA, with such Cost of New Entry equal to the average of all five Cost of New Entry areas for RTO and the average of the Cost of New Entry for all zones in an LDA, and the Net Energy and Ancillary Services Revenue Offset value equal to the 67th percentile of the Net Energy and Ancillary Services Revenue Offset for all zones in such LDA.

- iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

- A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.
 - C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- iv) Cost of New Entry
- A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	108,000
BGE, PEPCO (“CONE Area 2”)	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	105,500
PPL, MetEd, Penelec (“CONE Area 4”)	105,500

A-1) Cost of New Entry for 2025/2026 Delivery Year

A new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all CONE Areas.

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE for each CONE Area (except for CONE Area 5) shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

- (1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index

is further specified for each CONE Area in the PJM Manuals.

- (2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.
 - (3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.
 - (4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.
- C) For the 2026/2027 Delivery Year and 2027/2028 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	136,000
BGE, PEPCO (“CONE Area 2”)	142,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	147,600
PPL, MetEd, Penelec (“CONE Area 4”)	143,500

4")	
ComEd ("CONE Area 5")	150,800

- (1) For the 2027/2028 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, in accordance with the following:
 - (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.
 - (b) For CONE Areas 1 through 4, the Benchmark CONE for each CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).
 - (c) For the 2027/2028 Delivery Year, the CONE for CONE Area 5 for a given Delivery Year shall be set equal to the product of the CONE of CONE Area 3 as determined for the relevant Delivery Year in accordance with (a) and (b) above, multiplied by the asset life factor applicable to that Delivery Year where such asset life

factors is 1.0376 for the 2027/2028 Delivery Year.

- (d) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

- D) For the 2028/2029 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	218,000
BGE, PEPCO (“CONE Area 2”)	222,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	215,000
PPL, MetEd, Penelec (“CONE Area 4”)	216,000
ComEd (“CONE Area 5”)	248,000

- (1) Beginning with the 2029/2030 Delivery Year, the Cost of New Entry for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:
- (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time Cost of New Entry values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the Quarterly Census of Employment and Wages, which shall use NAICS

2371 Utility System Construction, Private, All Establishment Sizes (weighted 15%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction (weighted 10%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets (weighted 46%), and the Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2017=100, Seasonally Adjusted (weighted 29%), as each such index is further specified for each CONE Area in the PJM Manuals.

- (b) For CONE Areas 1 through 5, the Benchmark CONE for each CONE Area shall be the Cost of New Entry used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Cost of New Entry values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2028/2029 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the Cost of New Entry for subsequent Delivery Years).
 - (c) For the 2029/2030 Delivery Year through and including the 2031/2032 Delivery Year, the Cost of New Entry for CONE Area 5 for a given Delivery Year shall be multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.025 for the 2029/2030 Delivery Year, 1.054 for the 2030/2031 Delivery Year, and 1.088 for the 2031/2032 Delivery Year.
- v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):
 - A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel

prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of \$6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of \$2,199 per MW-year to be included through the 2025/2026 Delivery Year.

- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

- A) For the 2026/2027 and the 2027/2028 Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$1.19 per MWh and \$21,170 per start-up, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and

(e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

- A-1) For the 2028/2029 and subsequent Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the 67th percentile of all of the calculated zonal Net Energy and Ancillary Services Revenues Offsets that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each Net Energy and Ancillary Service Revenue Offset simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$2.65 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.
- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.
- C) “Forward Hourly LMPs” shall be determined as follows:
- (1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.
 - (2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading days as of 180 days prior to the Base Residual Auction.

For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

- (3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;
- (4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;
- (5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such monthly on-peak or off-peak period. The historical prices

used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

- (6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and
 - (7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.
- D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:
- (1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;
 - (2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point,

as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

- (3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be \$0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

- (1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;
- (2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;
- (3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;
- (4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;
- (5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement

Curve

- A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction

for a Delivery Year and will be used for such Base Residual Auction.

- B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement. The Variable Resource Requirement Curve shall be posted on the same timeline with the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement. Notwithstanding, for the 2029/2030 Delivery Year, the updated VRR Curve that incorporates any Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts shall be posted one month prior to the commencement of the relevant RPM Auction.
- C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.
- 1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 2) The PJM Members shall review the proposed values.
 - 3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

- D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.
- 1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 2) The PJM Members shall review the proposed methodology.
 - 3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) [Reserved]

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) Beginning with the 2029/2030 Delivery Year, the quantity of Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts used in establishing the Variable Resource Requirement Curve~~For the Delivery Years through May 31, 2018, the Demand Resource Factor;~~

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

vii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

viii) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that

corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement;
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement ([inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts](#)) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement ([inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts](#)), utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement ([inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts](#)) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement ([inclusive of any updated](#)

[adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts](#)), utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(v) (reserved)

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

- (A) [Reserved]
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;
- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

ATTACHMENT DD-4

INTERIM RESOURCE ADEQUACY SERVICE

I. INTRODUCTION

This Attachment DD-4 sets forth the terms and conditions governing the provision of Interim Resource Adequacy Service. As more fully set forth in this Attachment and the PJM Manuals, and in conjunction with the Reliability Assurance Agreement:

(a) Interim Resource Adequacy Service is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that are not in arrangements with new capacity additions to the PJM Region;

(b) Starting with the 2027/2028 Delivery Year, the Office of the Interconnection may, in accordance with the Manuals, instruct the implementation of an Interim Resource Adequacy Service Action prior to calling on Pre-Emergency Load Management Reductions Actions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages;

(c) The Large Load Registry maintained by the Office of the Interconnection, pursuant to the Reliability Assurance Agreement, shall inform which New Large Loads are eligible to be called on to provide Interim Resource Adequacy Service; and

(d) The Office of the Interconnection shall coordinate with Electric Distributors, and other Members as appropriate, on the provision of Interim Resource Adequacy Service and the compensation for providing Interim Resource Adequacy Service.

II. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

The Office of the Interconnection shall:

- (a) maintain the Large Load Registry, pursuant to Reliability Assurance Agreement, Schedule 11;
- (b) identify Eligible New Large Loads;
- (c) determine the megawatt quantity of New Large Loads eligible to provide Interim Resource Adequacy Service in each Electric Distributor zone/area for a given Delivery Year;
- (d) starting with the 2027/2028 Delivery Year, issue an Interim Resource Adequacy Service Action based on system conditions; and
- (e) request Electric Distributors to direct that a quantity of Eligible New Large Load Amounts in their respective zone(s)/area(s) be reduced in accordance with an Interim Resource Adequacy Service Action.

III. RESPONSIBILITIES OF ELECTRIC DISTRIBUTORS

Electric Distributors shall:

- (a) execute the Office of the Interconnection's directives to implement Interim Resource Adequacy Service Actions among the Eligible New Large Loads in the Electric Distributor's zone/area, which is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value and is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering;
- (b) coordinate with the Office of the Interconnection in developing and maintaining the Large Load Registry by providing the Office of the Interconnection any information or data the Electric Distributor believes appropriate to facilitate an accurate Large Load Registry, including applicable state or RERRA retail tariff or contractual obligations;
- (c) coordinate, as appropriate, with the relevant state(s) or RERRA(s), individual Load Serving Entities, and customers served by the Load Serving Entities in its zone/area to support transparent, effective, and orderly deployment of Interim Resource Adequacy Service; and
- (d) implement compensation program consistent with Tariff, Attachment DD-4, section X.

IV. DETERMINATION OF MAXIMUM INTERIM RESOURCE ADEQUACY SERVICE EACH ELIGIBLE NEW LARGE LOAD MAY PROVIDE IN A DELIVERY YEAR

(a) All Eligible New Large Loads shall be available to be requested to provide Interim Resource Adequacy Service by the Office of the Interconnection.

(b) The amount of Interim Resource Adequacy Service available to the Office of the Interconnection may change for each Delivery Year depending on the relationship of the amount of Capacity Resources committed, through Tariff, Attachment DD, for a given Delivery Year, and the Eligible New Large Load Amounts.

(i) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount greater than the sum (in MW) of all Eligible New Large Load Amounts, then all Eligible New Large Load Amounts is needed by the Office of the Interconnection to be available to provide Interim Resource Adequacy Service for that Delivery Year;

(ii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount less than the sum (in MW) of all Eligible New Large Load Amounts, then the difference (in MW) shall be the cumulative amount (in MW) of Eligible New Large Load Amounts that the Office of the Interconnection needs to be available to provide Interim Resource Adequacy Service for that Delivery Year; and

(iii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) equals or exceeds the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor), then the Office of the Interconnection does not need any Eligible New Large Loads to be available to provide Interim Resource Adequacy Service for that Delivery Year.

(c) For each Delivery Year that meets the requirements of Tariff, Attachment DD-4, sections IV(b)(i) or IV(b)(ii), the Office of the Interconnection shall determine:

(i) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis across the PJM Region for the Delivery Year; and

(ii) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis in each Electric Distributor zone/area for the Delivery Year, which shall be equal to

the product of the sum of all Eligible New Large Load Amounts needed in the PJM Region pursuant to Attachment DD-4, section IV(b) multiplied by the quotient of [(the sum of all Eligible New Large Load Amounts in the Electric Distributor's zone/area) divided by (the sum of all Eligible New Large Load Amounts in the PJM Region)].

V. DETERMINATION OF NEW LARGE LOADS ELIGIBILITY TO PROVIDE INTERIM RESOURCE ADEQUACY SERVICE

(a) All New Large Loads shall be Eligible New Large Loads to the extent that the sum of a New Large Load's Eligible New Large Load Amount is less than the New Large Load's registered peak load (in MW), as provided in the Large Load Registry. New Large Loads with a cumulative installed capacity equivalent of their BYONC arrangements and assigned Allocated RBP UCAP MW that equals or exceeds the New Large Load's registered peak load, as provided in the Large Load Registry, shall not be Eligible New Large Loads. New Large Loads that are located within an FRR Service Area cannot be Eligible New Large Loads.

(b) A New Large Load's Eligible New Large Load Amount shall be determined as follows:

(New Large Load's registered peak load (in MW), as provided in the Large Load Registry) minus (the sum of all BYONC arrangements with the New Large Load in accordance with Tariff, Attachment DD-4, section VII divided by the Forecast Pool Requirement for the first Delivery Year in which the BYONC cleared an RPM Auction, plus Allocated RBP UCAP MW assigned to the New Large Load, in accordance with Tariff, Attachment DD-4, section IX divided by the Forecast Pool Requirement for the first Delivery Year in which the Allocated RBP UCAP MW cleared an RPM Auction).

(c) For purposes of removing its eligibility to provide Interim Resource Adequacy Service, a New Large Load may enter into arrangements with BYONC supported by one or more resources.

VI. BRING YOUR OWN NEW CAPACITY CRITERIA

(a) (i) Capacity Resources that cleared an RPM Auction for the first time in the Base Residual Auction for the 2027/2028, 2028/2029, and 2029/2030 Delivery Years may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below.

(ii) Megawatts of Unforced Capacity that have not cleared an RPM Auction, other than those specified in subsection (a)(i) above, may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below. To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then megawatts of Unforced Capacity may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below and such megawatts (1) have not cleared in an RPM Auction conducted for a Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI.

(iii) With the exception of the RPM Auctions listed in subsection (a)(i) above, to the extent megawatts of Unforced Capacity that have cleared an RPM Auction before any arrangement with a New Large Load based on such megawatts was reported to the Office of the Interconnection, then such megawatts of Unforced Capacity cannot qualify as BYONC even if the underlying resource meets the criteria in subsection (b) below.

(b) To qualify as Bring Your Own New Capacity, resources must meet the following eligibility requirements:

(i) For generation and storage resources, the resource must be supported by one of the following:

- (1) a new-build generation resource including new resources that obtain Capacity Interconnection Rights transferred from deactivated resources or resources that have announced deactivation as of April 10, 2026;
- (2) the incremental capacity created by an uprate of Existing Generation Capacity Resources, but only to the extent such incremental capacity is created through an increase in such Generation Capacity Resource's installed capacity and increase in Capacity Interconnection Rights associated with that Generation Capacity Resource;
- (3) the incremental capacity created by the utilization of Surplus Interconnection Service;
- (4) repowering of a deactivated generation resource that deactivated prior to April 10, 2026; or

(5) incremental capacity, whether due to greater Unforced Capacity or a higher level of Capacity Interconnection Rights, created by an Existing Generation Capacity Resource's changing fuel type to a more efficient fuel type.

(ii) For Demand Resources or DER Capacity Aggregation Resources, the resource must qualify as a Planned Demand Resource or DER Capacity Aggregation Resource, as described in the RAA, Schedule 6 and Schedule 6.2 and:

(1) be composed of, or reliant on, any location not registered in or prior to the 2026/2027 Delivery Year at which an incremental amount at that location is the result of the registration of new generation or storage assets at the location. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, any location registered in the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met; and/or

(2) be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for or prior to the 2026/2027 Delivery Year. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met.

VII. BRING YOUR OWN NEW CAPACITY ARRANGEMENTS WITH NEW LARGE LOADS

- (a) For any BYONC to be in an arrangement with a New Large Load,
- (i) the Load Serving Entity serving the New Large Load or the applicable Electric Distributor shall report the BYONC in an arrangement with the New Large Load, in accordance with the PJM Manuals. The Office of the Interconnection may also accept information to the extent interconnection customers, Large Loads, Transmission Owners, or other entities voluntarily report any BYONC that may be in an arrangement with a New Large Load; and
 - (ii) the resource owner or entity with contractual authority to enter into a BYONC arrangement must certify to the Office of Interconnection, in accordance with the PJM Manuals, attesting to the arrangement with the New Large Load and that the BYONC will follow the requirements of Tariff, Attachment DD-4, section VIII.
- (b) For an arrangement between a New Large Load and BYONC to be effective for the 2027/2028 and 2028/2029 Delivery Years, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be met by April 1 for the first Delivery Year such arrangement is to result in a reduction in the New Large Load's Eligible New Large Load Amount. By April 15, the Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC.
- (c) For an arrangement between a New Large Load and BYONC to be effective for the 2029/2030 Delivery Year, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 50 days prior to the commencement of the 2029/2030 Base Residual Auction or by 30 days prior to the posting of the planning parameters for the Incremental Auctions arrangement for the 2029/2030 Delivery Year. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (d) For an arrangement between a New Large Load and BYONC to be effective for the 2030/2031 Delivery Year and subsequent Delivery Years, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 30 days prior to the posting of the planning parameters for the relevant RPM Auction for the initial Delivery Year the BYONC enters into an arrangement with the New Large Load. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (e) BYONC that is in an arrangement with a New Large Load must remain in such arrangement with that New Large Load unless and until the New Large Load is permanently out-of-service.
- (f) A physical resource may support multiple BYONC, each of which may be in an

arrangement with different New Large Loads, as long as no BYONC is in an arrangement with more than one New Large Load.

(g) A New Large Load may enter into an arrangement with discrete BYONC supported by different physical resources.

(h) A New Large Load may enter into an arrangement with BYONC in excess of its current Eligible Large Load Amount, e.g., to allow for expected growth in the New Large Load, and the full megawatt quantity of such BYONC shall be offered in the first RPM Auction for which the New Large Load is included in the Variable Resource Requirement Curve.

(i) (i) For any generation or storage resource, the Accredited UCAP of any BYONC shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load.

(ii) For Demand Resources or DER Capacity Aggregation Resources, the Accredited UCAP shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load and must be demonstrated each year for a 10-year period using the Demand Response or DER Capacity Aggregation Resources installed capacity for the first Delivery Year after the BYONC is in an arrangement with the New Large Load. For Demand Resources or DER Capacity Aggregation Resources that are also the actual New Large Load, there is no demonstration required for the initial Delivery Year only to not be an Eligible New Large Load.

VIII. BRING YOUR OWN NEW CAPACITY PARTICIPATION IN THE RELIABILITY PRICING MODEL

(a) All BYONC in an arrangement with a New Large Load must meet the requirements in Tariff, Attachment DD, section 5.5A and become Capacity Resources eligible to participate in RPM Auctions.

(b) All BYONC in an arrangement with a New Large Load must be offered into the RPM Auctions as Capacity Resources consistent with and pursuant to the capacity must-offer requirements and exceptions set forth in Tariff, Attachment DD, sections 6.6 and 6.6A. BYONC may not seek an exception to the capacity must-offer requirement to provide an external sale, as available under Tariff, Attachment DD, section 6.6(g) for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load.

(c) All BYONC in an arrangement with a New Large Load and committed through RPM Auctions will be subject to all capacity market rules, as set forth in Tariff, Attachments DD and DD-1.

(d) To the extent the resource supporting a BYONC arrangement is unavailable in a given Delivery Year, the seller of such resource will be subject to all relevant deficiency charges under Tariff, Attachment DD.

(e) All BYONC in an arrangement with a New Large Load and not qualifying for an exception pursuant to Tariff, Attachment DD, section 6.6(g), must be offered into the applicable RPM Auctions as price takers, i.e., \$0/MW-day UCAP for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load. To the extent the resource is a Demand Resource or DER Capacity Aggregation Resource, the BYONC shall participate in RPM Auctions for ten (10) consecutive Delivery Years as an Annual Demand Resource or DER Capacity Aggregation Resource, as applicable; provided, however, the seller of such Demand Resource or DER Capacity Aggregation Resource may, in accordance with Tariff, Attachment DD-4, section VII(a)(i) report to the Office of the Interconnection BYONC that replaces such BYONC, where such replacement shall be for the remainder of the replaced BYONC's ten-year RPM Auction participation commitment and the replaced BYONC (and its supporting registrations) may no longer provide BYONC. In such event, the replacement BYONC would need to be supported by the certification required by Tariff, Attachment DD-4, section VII(a)(ii), and such replacement arrangement must be effective coincident with the initial BYONC releasing its arrangement.

(f) To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then any existing BYONC are relieved of the obligations under this Tariff, Attachment DD-4, section VIII.

IX. ALLOCATION OF RBP UCAP MW

(a) Each Electric Distributor zone/area allocated RBP Charges pursuant to Tariff, Attachment DD, section 18.3(a) shall be allocated RBP UCAP MW on a pro-rata basis using the Electric Distributor zone/area's assigned share of the total Final RBP Target MW across all zone/areas.

(b) Each New Large Load's Allocated RBP UCAP MW shall be determined as follows:

(i) Each Electric Distributor allocated RBP UCAP MW shall inform the Office of the Interconnection how such RBP UCAP MW should be further allocated among the New Large Loads located in the Electric Distributor's zone/area; or

(ii) In the event the Electric Distributor has not informed the Office of the Interconnection how its RBP UCAP MW should be further allocated by April 1 before a given Delivery Year, the Office of the Interconnection shall allocate such RBP UCAP MW to the Electric Distributor's zone/area pro-rata among all New Large Loads located in the zone/area.

(c) The Office of the Interconnection shall list in the Large Load Registry each New Large Load's Allocated RBP UCAP MW.

X. COMPENSATION FOR PROVIDING INTERIM RESOURCE ADEQUACY SERVICE

(a) The rate for the provision of Interim Resource Adequacy Service shall be 50% of the Non-Performance Charge Rate specified in Tariff, Attachment DD, section 10A(e), unless any Eligible New Large Load elects to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service as contemplated by Tariff, Attachment DD-4, section X(c). If any Eligible New Large Load so elects to accept less than 50% of the Non-Performance Charge Rate or waives in its entirety receipt of compensation for the provision of wholesale Interim Resource Adequacy Service, the wholesale rate for the provision of Interim Resource Adequacy Service shall reflect the accepted sum less than 50% of the Non-Performance Charge Rate or if compensation is waived entirely, the rate shall be zero dollars.

(b) (i) Following an Interim Resource Adequacy Event, unless the Electric Distributor informs the Office of the Interconnection otherwise in accordance with Tariff, Attachment DD-4, section X(b)(ii), the Electric Distributor shall be responsible for compensating all Eligible New Large Loads that provided Interim Resource Adequacy Service for up to the amount of such service provided. The Electric Distributor shall be responsible for charging customers in its zone/area to fund any such compensation.

(ii) The Electric Distributor may request the Office of the Interconnection to compensate certain Members for the provision of Interim Resource Adequacy Service and to assess charges on certain Load Serving Entities within the Electric Distributor's zone/area to fund such compensation. In support of such request, as further set forth in the PJM Manuals, the Electric Distributor shall (1) identify each Member to be compensated and provide the level of compensation and (2) identify each Load Serving Entity to be charged and the level of charge.

(iii) The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to pay any amounts owed to another party under this section. In the event the Electric Distributor requests the Office of the Interconnection facilitate the billing associated with an Interim Resource Adequacy Event, such billing shall be considered a bilateral transaction between the Electric Distributor and the identified Members and PJMSettlement shall not be a contracting party to the settlement.

(c) Nothing in this Tariff, Attachment DD-4, section X shall interfere with any Eligible New Large Load's election to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service.

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

“Accredited UCAP” shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

“Accredited UCAP Factor” shall mean, through the 2024/2025 Delivery Year, one minus EFORD, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource’s Accredited UCAP to the Capacity Resource’s installed capacity.

Agreement:

“Agreement” shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

“Annual Demand Resource” shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast

prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

“Applicable Regional Entity” shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

“Base Capacity Resource” shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

“Base Residual Auction” shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such

consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource or DER Capacity Aggregation Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall have the meaning provided in the Tariff.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and

deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on

such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

“Capacity Only Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

“Capacity Performance Resource” shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

“Capacity Resources” shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6; or (iv) generation and load reduction capability provided by a DER Capacity Aggregation Resource, pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.2 and the PJM Manuals.

Capacity Resource Provider:

“Capacity Resource Provider” shall mean a Member that (1) owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity; (2) or a DER Aggregator that has a contractual relationship to use a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource.

Capacity Storage Resource Class:

“Capacity Storage Resource Class” shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of (1) Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours or; (2) storage device Component DER. The characteristic duration of an Energy Storage Resource Class is the ratio of

the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

“Capacity Transfer Right” shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

“Coal Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

“Combination Resource” shall mean a Generation Capacity Resource, or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall have the same meaning as in the Tariff.

Complex Hybrid Class:

“Complex Hybrid Class” shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

DER Aggregator Officer Certification Form:

“DER Aggregator Officer Certification Form” shall mean a DER Aggregator’s certification as to an intended DER Capacity Aggregation Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

DER Capacity Aggregation Resource Sell Offer Plan:

“DER Capacity Aggregation Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of a DER Capacity Aggregation Resource in an RPM Auction, or an intended inclusion of a DER Capacity Aggregation Resource in an FRR Capacity Plan.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource that is a Generation Capacity Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Variable Resource and Combination Resource, that is an individual Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, the device’s maximum energy production capability, as defined by the resource’s state interconnection agreement; or (iii) for each Limited Duration Resource, the sustained level of output that the device can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

“ELCC Class” shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

“ELCC Class Rating” shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

“ELCC Class UCAP” shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

“ELCC Portfolio UCAP” shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

“ELCC Resource” shall mean a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

“ELCC Resource Performance Adjustment” shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the

average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

“Exigent Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing DER Capacity Aggregation Resource:

“Existing DER Capacity Aggregation Resource” shall mean a DER Capacity Aggregation Resource for which the DER Aggregator has identified existing Component DER that are registered in a DER Capacity Aggregation Resource for the current Delivery Year with PJM (even if not registered by such DER Aggregator) and that the DER Aggregator reasonably

expects to have under a contract to generate or reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such DER Capacity Aggregation Resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall have the meaning specified in the Tariff.

Firm Service Level:

“Firm Service Level” or “FSL” of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. “Firm Service Level” or “FSL” of Demand Resource shall mean the pre-determined level to which an end-use customer’s load shall be reduced, upon notification from the Curtailment Service Provider’s market operations center or its agent.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

“Fixed-Tilt Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

“Full Program Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

“Gas Combined Cycle Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

“Gas Combined Cycle Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

“Gas Combustion Turbine Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

“Gas Combustion Turbine Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

“Generation Capacity Resource” shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

“Hybrid Resource Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, the individual components would be in a Capacity Storage Resource Class, a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

“Hydropower With Non-Pumped Storage” shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation

Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

“Hydropower With Non-Pumped Storage Class” shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

- (i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and
- (ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

“Intermittent Hydropower Class” shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

“IOU” shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

“Intermittent Landfill Gas Class” shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load:

“Large Load” shall mean end-use customer(s) load that has a cumulative peak load of 50 megawatts or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site as further described in the PJM Manuals.

Large Load Adjustment:

“Large Load Adjustment” shall mean any MW quantity of adjustments to summer peak load at the “zone/area” level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a “zone/area” is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

Limited Demand Resource:

“Limited Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

“Limited Duration Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and

energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

“Nominal PRD Value” shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

“Non-Retail Behind the Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

“Nuclear Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

“Obligation Peak Load” shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

“Offshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The

characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

“Other Limited Duration Combination Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

“Other Unlimited Resource Class” shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

“Other Variable Resource Class” shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

“Peak Shaving Adjustment” shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

“Performance Assessment Interval” shall have the meaning specified in Tariff, Attachment DD.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Governing Agreements:

“PJM Governing Agreements” shall have the meaning provided in the Operating Agreement.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

“Planned Demand Resource” shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned DER Capacity Aggregation Resource:

A “Planned DER Capacity Aggregation Resource” shall mean any DER Capacity Aggregation Resource that does not currently have the capability to provide generation or reduction in demand, but that is scheduled to be capable of providing such generation or reduction in demand on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6.2. As set forth in Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1, a DER Aggregator submitting a DER Capacity Aggregation Resource Sell Offer Plan shall identify in such plan all DER Capacity Aggregation Resources in excess of those that qualify as Existing DER Capacity Aggregation Resources. A Planned DER Capacity Aggregation Resource must comply with all provisions of the DER Aggregator Participation Model described in Tariff, Attachment K-Appendix, section 1.4B and Operating Agreement, Schedule 1, section 1.4B, prior to the applicable Delivery Year.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the

Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has documentation which is functionally equivalent to an approved Decision Point I submission under the PJM Tariff Part VII or VIII as applicable or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to an approved Decision Point II submission under the PJM Tariff Part VII or VIII as applicable, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to a Generation Interconnection Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to be delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, Part VII or Part VIII, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, all the requirements for an approved Decision Point I submission have been met under Tariff Part VII or VIII (or, for resources for which a Decision Point I submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point I submission) prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, all the requirements for an approved Decision Point II submission have been met under Tariff Part VII or VIII (or, for resources for

which a Decision Point II submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point II submission) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) a Generation Interconnection Agreement or Wholesale Market Participation Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

“Portfolio Expected Unserved Energy” shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Performance Assessment Interval that triggers a PRD performance assessment or a Non-PAI Event, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example,

without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

“Tracking Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

“Unlimited Resource” shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

“Variable Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean the average of the Demand Resource customer’s specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

“Zone” or “Zonal” shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

“Zonal Winter Weather Adjustment Factor” or “ZWWAF” shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

7.8 Requirement to Designate Network Resources to Serve Capacity Needs for New Large Loads and Conditional Requirement to Provide Interim Resource Adequacy Service

Effective June 1, 2027, each LSE that desires to provide Network Transmission Service to support New Large Loads must designate one or more Generation Capacity Resources or Capacity Storage Resources that had not cleared an RPM Auction as Network Resource(s) in a cumulative amount that equals or exceeds the LSE's New Large Load's peak load (in MW) as reported in the Large Load Registry pursuant to RAA, Schedule 11 or such New Large Load may be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response. If, on June 1, 2027, an LSE has not so designated such Network Resource(s) as BYONC with which it has entered into an arrangement in accordance with this requirement and Tariff, Attachment DD-4, then the amount of New Large Load that is the difference between its reported peak load and its designated Bring Your Own New Capacity and assigned Allocated RBP UCAP MW will be subject to the rates, terms, and conditions of Interim Resource Adequacy Service, as set forth in Tariff, Attachment DD-4.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources. An FRR Entity may not include in its FRR Capacity Plan any MW quantity of Existing Generation Capacity Resource in excess of what such FRR Entity owned or contracted by such FRR Entity prior to June 1, 2027, to serve New Large Load.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the Base Zonal FRR Scaling Factor times the summation of the FRR Entity's MW share of the Zonal Weather Normalized Summer Peak last determined prior to the Base Residual Auction for such Delivery Year plus the Obligation Peak Load MW associated with any Load Adjustment specified for such Delivery Year for any "zone/area" served by the FRR Entity's Capacity Plan. The Obligation Peak Load MW associated with a Load Adjustment specified for a "zonal/area" is determined as set forth in RAA, Schedule 8, section B.

The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand

must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal $[(ZPLDY - ZLA) / ZWNSP]$, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year;

ZLA = the Zonal MW quantity of Load Adjustment for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM

Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, an FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region (“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), or Mid-Atlantic Region (“MAR”), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in \$/MW-day, times the shortfall of

Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in \$/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

SCHEDULE 11

DATA SUBMITTALS

A. To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.
2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.
3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.
4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

B. 1. (a) Each Party shall submit, or cause to be submitted, to the Office of the Interconnection the following information, as may be further described in the PJM Manuals, related to each Large Load served by the Party:

- Eligible Customer/Network Customer for Large Load;
- Description of Large Load;
- Location(s) (Control Zone, Electric Distributor zone/area, where a zone/area is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering);

- In-service date for each increment of load;
- Peak shaving adjustment value pursuant to a state program codified in state law and whether and how it meets the requirements of Tariff, Attachment DD-2;
- Delivery point / Point(s) of interconnection (include all if more than one);
- Peak load quantity (MW) and ramp schedule, if applicable;
- Telemetry specifications;
- BYONC quantity (MW) and ramp schedule, if applicable;
- Allocated RBP UCAP MW quantity (MW), if applicable;
- Backup generation (MW), including fuel type and relevant permitting limitations;
- Contracts or service agreements between the Large Load and the LSE;
- Points of contact at the applicable Transmission Owner, Electric Distributor, and Load Serving Entity;
- EMS B1/B2/B3 name (for the applicable Transmission Owner, Electric Distributor); and
- Additional details and contents as necessary, in accordance with the PJM Manuals.

(b) The Parties acknowledge that information related to the development and maintenance of the Large Load Registry may be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement and the Tariff.

(c) The Office of the Interconnection may review information and coordinate with the applicable Transmission Owner and Electric Distributor as needed, regarding the validity of the information provided, including through requesting additional information as the Office of the Interconnection deems necessary, as further set forth in the PJM Manuals. The Office of the Interconnection also may consult with the Large Load.

(d) Based on the information provided, or caused to be provided, by each Party, as well as other information provided by, for example, Electric Distributors, the Office of the Interconnection shall maintain a registry of all Large Loads, and update it periodically. To the extent such documents, data, or other information provided to the Office of the Interconnection has been designated as confidential by a Party, Electric Distributor, or other entity supplying the information, the Office of the Interconnection shall maintain the confidentiality of the information provided under this RAA, Schedule 11, section B consistent with its obligations under Operating Agreement, section 18.17. Information maintained in the Large Load registry may be available to Authorized Commissions, Transmission Owners, Electric Distributors, Load Serving Entities, the Market Monitoring Unit, and FERC subject to appropriate data protection safeguards required by Operating Agreement, section 18.17.

(e) The Office of the Interconnection shall post aggregate data from the Large Load Registry on the PJM website, aggregated by Electric Distributor zone/area, where

possible and in a manner consistent with existing confidentiality protections in the PJM Governing Agreements.

2. (a) Each Party serving or contracted to serve a Large Load that is or will be in service prior to June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection by March 1, 2027.

(b) Each Party serving or contracted to serve a New Large Load that will be in service on or after June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection before the in-service date of the Large Load.

(c) Each Party contracted to serve a New Large Load shall provide the location(s) as required by RAA, Schedule 11.B.1 to the Office of the Interconnection before determination of the final PJM Regional Peak Load Forecast for the effective RPM Auction for the Delivery Year in which the New Large Load is expected to be in-service starting with the 2028 PJM Regional Peak Load Forecast.

Each Party shall promptly inform the Office of the Interconnection of any change in the information required by RAA, Schedule 11.B.1 with respect to a Large Load served by the Party, including whether the Party no longer serves the Large Load or has acquired the contractual right to serve a registered Large Load.

3. The information provided pursuant to RAA, Schedule 11, section B will be used, to the extent necessary, for purposes including but not limited to implementation of Interim Resource Adequacy Service, which is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that have not entered into an arrangement with new capacity additions to the PJM Region, as more fully set forth in Tariff, Attachment DD-4.

Attachment B

Revisions to the PJM Open Access Transmission Tariff and Resource Adequacy Agreement

(Clean Format)

Definitions – A - B**30-minute Reserve:**

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Allocated RBP UCAP MW:

“Allocated RBP UCAP MW” shall mean the RBP UCAP MW allocated to a New Large Load in accordance with Tariff, Attachment DD-4, section IX.

Ambient-Adjusted Rating:

“Ambient-Adjusted Rating” (AAR) shall mean a Transmission Facility Rating that:

- (a) Applies to a time period of not greater than one hour.
- (b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
- (c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
- (d) Is evaluated at least each hour, if not more frequently.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network

Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

“Batch Load Economic Load Response Participant Resource” shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such

generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall mean megawatts of Unforced Capacity that meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI. Megawatts of Unforced Capacity that have been previously included in an FRR Capacity Plan prior to the 2027/2028 Delivery Year do not qualify as BYONC. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then BYONC that has been included previously in an FRR Capacity Plan prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI do not qualify as BYONC.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – E - F**Economic-based Enhancement or Expansion:**

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Load Response Regulation Only Participant:

“Economic Load Response Regulation Only Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, and is only eligible to participate in the PJM Regulation market.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORD:

“EFORD” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Eligible New Large Loads:

“Eligible New Large Loads” shall mean a New Large Load eligible to provide Interim Resource Adequacy Service in accordance with Tariff, Attachment DD-4, section V.

Eligible New Large Load Amount:

“Eligible New Large Load Amount” shall mean the total megawatt value of load an Eligible New Large Load may be required to make available for Interim Resource Adequacy Service in an Electric Distributor zone/area.

Emergency Action:

“Emergency Action” shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when

dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has an operational limitation due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Excluded LDA New Large Load Amounts:

“Excluded LDA New Large Load Amounts” shall mean, converted in UCAP terms by estimating the impact on required imports to a Locational Deliverability Area and exclusive of any load in

an FRR Service Area, [the sum of all New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast for the relevant Delivery Year] minus [New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the Locational Deliverability Area or (ii) assigned Allocated RBP UCAP MW in Locational Deliverability Area].

Excluded RTO New Large Load Amounts

“Excluded RTO New Large Load Amounts” shall mean, converted in UCAP terms by using the Forecast Pool Requirement and exclusive of any load in an FRR Service Area, [the sum of all New Large Loads across the PJM Region in the load forecast for the relevant Delivery Year] minus [New Large Loads across the PJM Region that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the RTO or (ii) assigned Allocated RBP UCAP MW in the RTO].

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time

periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an

invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account.

Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – I – J - K**IDR Transfer Agreement:**

“IDR Transfer Agreement” shall mean an agreement to transfer, subject to the terms of Tariff, Part VI, section 237, Incremental Deliverability Rights to a party for the purpose of eliminating or reducing the need for Local or Network Upgrades that would otherwise have been the responsibility of the party receiving such rights.

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall have the same meaning provided in the Operating Agreement.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Incidental Expenses:

“Incidental Expenses” shall mean those expenses incidental to the performance of construction pursuant to an Interconnection Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Interconnected Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Customer Facility and for the Interconnection Facilities.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction) shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed

circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Incremental Auction Revenue Rights:

“Incremental Auction Revenue Rights” shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Available Transfer Capability Revenue Rights:

“Incremental Available Transfer Capability Revenue Rights” shall mean the rights to revenues that are derived from incremental Available Transfer Capability created by the addition of Merchant Transmission Facilities or of one or more Customer-Funded Upgrades.

Incremental Capacity Transfer Right:

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

“Incremental Deliverability Rights” or “IDRs” shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Interconnection Customer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Incremental Rights-Eligible Required Transmission Enhancements:

“Incremental Rights-Eligible Required Transmission Enhancements” shall mean Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Tariff, Schedule 12) and meet one of the following criteria: (1) cost responsibility is assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Independent Auditor:

“Independent Auditor” shall mean an external accountant or external accounting firm who is not an employee of, not otherwise related to, not obligated to, has no interest in, and is independent in the performance of professional services for, the entity he/she/it is auditing, its management and/or its owners.

Initial Operation:

“Initial Operation” shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Tariff, Attachment O-Appendix 2, section 1.4 (an Interconnection Service Agreement).

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Tariff, Attachment K-Appendix, section 2.2.

Interconnected Entity:

“Interconnected Entity” shall mean either the Interconnection Customer or the Interconnected Transmission Owner; Interconnected Entities shall mean both of them.

Interconnected Transmission Owner:

“Interconnected Transmission Owner” shall mean the Transmission Owner to whose transmission facilities or distribution facilities Customer Interconnection Facilities are, or as the case may be, a Customer Facility is, being directly connected. When used in an Interconnection

Construction Service Agreement, the term may refer to a Transmission Owner whose facilities must be upgraded pursuant to the Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

Interconnection Construction Service Agreement:

“Interconnection Construction Service Agreement” shall mean the agreement entered into by an Interconnection Customer, Interconnected Transmission Owner and the Transmission Provider pursuant to Tariff, Part VI, Subpart B and in the form set forth in Tariff, Attachment P, relating to construction of Attachment Facilities, Network Upgrades, and/or Local Upgrades and coordination of the construction and interconnection of an associated Customer Facility. A separate Interconnection Construction Service Agreement will be executed with each Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

“Interconnection Customer” shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

“Interconnection Facilities” shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

“Interconnection Feasibility Study” shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

“Interconnection Party” shall mean a Transmission Provider, Interconnection Customer, or the Interconnected Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

“Interconnection Request” shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

“Interconnection Service” shall mean the physical and electrical interconnection of the Customer Facility with the Transmission System pursuant to the terms of Tariff, Part IV and Tariff, Part VI and the Interconnection Service Agreement entered into pursuant thereto by Interconnection Customer, the Interconnected Transmission Owner and Transmission Provider.

Interconnection Service Agreement:

“Interconnection Service Agreement” shall mean an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Tariff, Part IV and Tariff, Part VI.

Interconnection Studies:

“Interconnection Studies” shall mean the Interconnection Feasibility Study, the System Impact Study, and the Facilities Study described in Tariff, Part IV and Tariff, Part VI.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Interim Resource Adequacy Service:

“Interim Resource Adequacy Service” shall mean a load reduction service through which New Large Loads reduce load as directed by the applicable Electric Distributor in response to an Interim Resource Adequacy Service Action requested by the Office of the Interconnection. Such reductions in load may be eligible for compensation pursuant to Attachment DD-4, section X.

Interim Resource Adequacy Service Action:

“Interim Resource Adequacy Service Action” shall mean an Operating Instruction, as defined by NERC, issued from the Office of the Interconnection to reduce load prior to calling on Pre-Emergency Load Management Reductions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.

Intermittent Resource:

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

Internal Credit Score:

“Internal Credit Score” shall mean a composite numerical score determined by PJMSettlement using quantitative and qualitative metrics to estimate various predictors of a credit event happening to a Market Participant that may trigger a credit event.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

Interruption:

“Interruption” shall mean a reduction in non-firm transmission service due to economic reasons pursuant to Tariff, Part II, section 14.7.

IROL Critical Resource:

“IROL Critical Resource” shall mean a generation resource that the Office of the Interconnection designates, pursuant to NERC Reliability Standards, as having an interconnection reliability operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.

Jointly Owned Cross-Subsidized Capacity Resource:

“Jointly Owned Cross-Subsidized Capacity Resource” shall mean a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Definitions – L – M – N**Large Load:**

“Large Load” shall have the meaning provided in the Reliability Assurance Agreement.

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model

employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with

preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD, section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum State of Charge:

“Maximum State of Charge” shall mean the maximum State of Charge that should not be exceeded, measured in units of megawatt-hours.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker

opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

Minimum State of Charge:

“Minimum State of Charge” shall mean the minimum State of Charge that should be maintained in units of megawatt-hours.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

“Mixed Technology Facility” shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

“Near-Term Transmission Service” shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. “Near-Term Transmission Service” includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a

Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New Large Load:

“New Large Load” shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1, 2027, or (b) incremental load in-service after June 1, 2027, that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then New Large Load shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met or (b) incremental load in-service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Curtailment Charge:

“Non-Curtailment Charge” shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

“Non-PAI Event” shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

Definitions – T – U - V**Tangible Net Worth:**

“Tangible Net Worth” shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

“Third Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

“Trade Reference” shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Facility Rating:

“Transmission Facility Rating” shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment.

Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

“Transmission Service” shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

“Transmission Service Request” shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

“Transmission System” shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

“Unconstrained LDA Group” shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

“Unforced Capacity” shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any changes in the Reliability Requirement, Excluded RTO New Large Load Amounts, and/or Excluded LDA New Large Load Amounts from the Base Residual Auction to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile

For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

“Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

“Virtual Transactions Net Activity” shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, the Base Residual Auction for the 2026/2027 Delivery Year shall be conducted in July 2025; the Base Residual Auction for the 2027/2028 Delivery Year shall be conducted in December 2025; the Base Residual Auction for the 2028/2029 Delivery Year shall be conducted in June 2026; and the Base Residual Auction for the 2029/2030 Delivery Year shall be conducted in December 2026. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for the 2025/2026 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2025; for the 2026/2027 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2026; for the 2027/2028 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which will commence on July 2026 and February 2027, respectively; for the 2028/2029 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which shall commence on July 2027 and February 2028, respectively.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement or the LDA Reliability Requirement (inclusive of any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement;

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained; or

iii) regarding a Generation Capacity Resource that is subject to Tariff, Attachment DD, section 5.3(b), (a) the Office of Interconnection determines prior to the Third Incremental Auction that such resource will not meet the criteria set forth in Tariff, Attachment DD, section 5.3(b)(i) for the relevant Delivery Year or (b) such resource's final Accredited UCAP is less than the UCAP amount considered in the Base Residual Auction in which the resource was deemed to be the subject of a Sell Offer.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the

PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, decrease in Accredited UCAP Factor, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement or Locational Deliverability Area Reliability Requirement for such Delivery Year. For any auction, the Updated Forecast Peak Load applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis.
- For the 2025/2026 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 98.9%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.6%]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.8%].
- For the 2026/2027 Delivery Year and 2027/2028 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
- For the 2028/2029 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the

applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

- For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.0%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
 - For the 2029/2030 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%];
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%.

- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
 - For the 2030/2031 Delivery Year and for subsequent Delivery Years, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%];
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%].
- ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:
- A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or
 - B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or
 - C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year, the Eastern Mid-Atlantic Region

("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, beginning with the 2029/2030 Delivery Year, the points on the LDA Variable Resource Requirement Curves will be reduced by the relevant Excluded LDA New Large Load Amounts. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For Delivery Years up to and including the 2027/2028 Delivery Year for each such LDA, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA.

For the 2028/2029 Delivery Year and for subsequent Delivery Years for each such LDA, the Office of the Interconnection shall determine the applicable Cost of New Entry and Net Energy and Ancillary Services Revenue Offset value for each LDA, with such Cost of New Entry equal to the average of all five Cost of New Entry areas for RTO and the average of the Cost of New Entry for all zones in an LDA, and the Net Energy and Ancillary Services Revenue Offset value equal to the 67th percentile of the Net Energy and Ancillary Services Revenue Offset for all zones in such LDA.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of

the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

- A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.
 - C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- iv) Cost of New Entry
- A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	108,000
BGE, PEPCO (“CONE Area 2”)	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	105,500
PPL, MetEd, Penelec (“CONE Area 4”)	105,500

A-1) Cost of New Entry for 2025/2026 Delivery Year

A new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all CONE Areas.

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE for each CONE Area (except for CONE Area 5) shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

- (1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index

is further specified for each CONE Area in the PJM Manuals.

- (2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.
 - (3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.
 - (4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.
- C) For the 2026/2027 Delivery Year and 2027/2028 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	136,000
BGE, PEPCO ("CONE Area 2")	142,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3")	147,600

PPL, MetEd, Penelec (“CONE Area 4”)	143,500
ComEd (“CONE Area 5”)	150,800

- (1) For the 2027/2028 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:
 - (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.
 - (b) For CONE Areas 1 through 4, the Benchmark CONE for each CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).
 - (c) For the 2027/2028 Delivery Year, the CONE for CONE Area 5 for a given Delivery Year shall be set equal to the product of the CONE of CONE Area 3 as determined for the relevant Delivery Year in accordance with (a) and (b) above, multiplied by the asset life factor applicable

to that Delivery Year where such asset life factors is 1.0376 for the 2027/2028 Delivery Year.

- (d) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

- D) For the 2028/2029 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	218,000
BGE, PEPCO (“CONE Area 2”)	222,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	215,000
PPL, MetEd, Penelec (“CONE Area 4”)	216,000
ComEd (“CONE Area 5”)	248,000

- (1) Beginning with the 2029/2030 Delivery Year, the Cost of New Entry for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:
- (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time Cost of New Entry values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the Quarterly Census of

Employment and Wages, which shall use NAICS 2371 Utility System Construction, Private, All Establishment Sizes (weighted 15%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction (weighted 10%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets (weighted 46%), and the Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2017=100, Seasonally Adjusted (weighted 29%), as each such index is further specified for each CONE Area in the PJM Manuals.

- (b) For CONE Areas 1 through 5, the Benchmark CONE for each CONE Area shall be the Cost of New Entry used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Cost of New Entry values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2028/2029 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the Cost of New Entry for subsequent Delivery Years).
 - (c) For the 2029/2030 Delivery Year through and including the 2031/2032 Delivery Year, the Cost of New Entry for CONE Area 5 for a given Delivery Year shall be multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.025 for the 2029/2030 Delivery Year, 1.054 for the 2030/2031 Delivery Year, and 1.088 for the 2031/2032 Delivery Year.
- v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):
 - A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate

and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of \$6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of \$2,199 per MW-year to be included through the 2025/2026 Delivery Year.

- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

- A) For the 2026/2027 and the 2027/2028 Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$1.19 per MWh and \$21,170 per start-up, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder

appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

- A-1) For the 2028/2029 and subsequent Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the 67th percentile of all of the calculated zonal Net Energy and Ancillary Services Revenues Offsets that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each Net Energy and Ancillary Service Revenue Offset simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$2.65 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.
- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.
- C) “Forward Hourly LMPs” shall be determined as follows:
 - (1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.
 - (2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading

days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

- (3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;
- (4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;
- (5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such

monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

- (6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and
 - (7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.
- D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:
- (1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;
 - (2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-

time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

- (3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be \$0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

- (1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;
- (2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;
- (3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;
- (4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;
- (5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement

Curve

- A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.
- B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement. The Variable Resource Requirement Curve shall be posted on the same timeline with the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement. Notwithstanding, for the 2029/2030 Delivery Year, the updated VRR Curve that incorporates any Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts shall be posted one month prior to the commencement of the relevant RPM Auction.
- C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.
 - 1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 2) The PJM Members shall review the proposed values.
 - 3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base

Residual Auction for the first Delivery Year in which the new values would be applied.

- D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.
- 1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 2) The PJM Members shall review the proposed methodology.
 - 3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) [Reserved]

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORD, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) Beginning with the 2029/2030 Delivery Year, the quantity of Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts used in establishing the Variable Resource Requirement Curve;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

vii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

viii) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORD values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all

Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement;
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts), utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large

Load Amounts), utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(v) (reserved)

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

- (A) [Reserved]
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;
- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

ATTACHMENT DD-4

INTERIM RESOURCE ADEQUACY SERVICE

I. INTRODUCTION

This Attachment DD-4 sets forth the terms and conditions governing the provision of Interim Resource Adequacy Service. As more fully set forth in this Attachment and the PJM Manuals, and in conjunction with the Reliability Assurance Agreement:

(a) Interim Resource Adequacy Service is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that are not in arrangements with new capacity additions to the PJM Region;

(b) Starting with the 2027/2028 Delivery Year, the Office of the Interconnection may, in accordance with the Manuals, instruct the implementation of an Interim Resource Adequacy Service Action prior to calling on Pre-Emergency Load Management Reductions Actions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages;

(c) The Large Load Registry maintained by the Office of the Interconnection, pursuant to the Reliability Assurance Agreement, shall inform which New Large Loads are eligible to be called on to provide Interim Resource Adequacy Service; and

(d) The Office of the Interconnection shall coordinate with Electric Distributors, and other Members as appropriate, on the provision of Interim Resource Adequacy Service and the compensation for providing Interim Resource Adequacy Service.

II. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

The Office of the Interconnection shall:

- (a) maintain the Large Load Registry, pursuant to Reliability Assurance Agreement, Schedule 11;
- (b) identify Eligible New Large Loads;
- (c) determine the megawatt quantity of New Large Loads eligible to provide Interim Resource Adequacy Service in each Electric Distributor zone/area for a given Delivery Year;
- (d) starting with the 2027/2028 Delivery Year, issue an Interim Resource Adequacy Service Action based on system conditions; and
- (e) request Electric Distributors to direct that a quantity of Eligible New Large Load Amounts in their respective zone(s)/area(s) be reduced in accordance with an Interim Resource Adequacy Service Action.

III. RESPONSIBILITIES OF ELECTRIC DISTRIBUTORS

Electric Distributors shall:

- (a) execute the Office of the Interconnection's directives to implement Interim Resource Adequacy Service Actions among the Eligible New Large Loads in the Electric Distributor's zone/area, which is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value and is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering;
- (b) coordinate with the Office of the Interconnection in developing and maintaining the Large Load Registry by providing the Office of the Interconnection any information or data the Electric Distributor believes appropriate to facilitate an accurate Large Load Registry, including applicable state or RERRA retail tariff or contractual obligations;
- (c) coordinate, as appropriate, with the relevant state(s) or RERRA(s), individual Load Serving Entities, and customers served by the Load Serving Entities in its zone/area to support transparent, effective, and orderly deployment of Interim Resource Adequacy Service; and
- (d) implement compensation program consistent with Tariff, Attachment DD-4, section X.

IV. DETERMINATION OF MAXIMUM INTERIM RESOURCE ADEQUACY SERVICE EACH ELIGIBLE NEW LARGE LOAD MAY PROVIDE IN A DELIVERY YEAR

(a) All Eligible New Large Loads shall be available to be requested to provide Interim Resource Adequacy Service by the Office of the Interconnection.

(b) The amount of Interim Resource Adequacy Service available to the Office of the Interconnection may change for each Delivery Year depending on the relationship of the amount of Capacity Resources committed, through Tariff, Attachment DD, for a given Delivery Year, and the Eligible New Large Load Amounts.

(i) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount greater than the sum (in MW) of all Eligible New Large Load Amounts, then all Eligible New Large Load Amounts is needed by the Office of the Interconnection to be available to provide Interim Resource Adequacy Service for that Delivery Year;

(ii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount less than the sum (in MW) of all Eligible New Large Load Amounts, then the difference (in MW) shall be the cumulative amount (in MW) of Eligible New Large Load Amounts that the Office of the Interconnection needs to be available to provide Interim Resource Adequacy Service for that Delivery Year; and

(iii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) equals or exceeds the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor), then the Office of the Interconnection does not need any Eligible New Large Loads to be available to provide Interim Resource Adequacy Service for that Delivery Year.

(c) For each Delivery Year that meets the requirements of Tariff, Attachment DD-4, sections IV(b)(i) or IV(b)(ii), the Office of the Interconnection shall determine:

(i) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis across the PJM Region for the Delivery Year; and

(ii) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis in each Electric Distributor zone/area for the Delivery Year, which shall be equal to

the product of the sum of all Eligible New Large Load Amounts needed in the PJM Region pursuant to Attachment DD-4, section IV(b) multiplied by the quotient of [(the sum of all Eligible New Large Load Amounts in the Electric Distributor's zone/area) divided by (the sum of all Eligible New Large Load Amounts in the PJM Region)].

V. DETERMINATION OF NEW LARGE LOADS ELIGIBILITY TO PROVIDE INTERIM RESOURCE ADEQUACY SERVICE

(a) All New Large Loads shall be Eligible New Large Loads to the extent that the sum of a New Large Load's Eligible New Large Load Amount is less than the New Large Load's registered peak load (in MW), as provided in the Large Load Registry. New Large Loads with a cumulative installed capacity equivalent of their BYONC arrangements and assigned Allocated RBP UCAP MW that equals or exceeds the New Large Load's registered peak load, as provided in the Large Load Registry, shall not be Eligible New Large Loads. New Large Loads that are located within an FRR Service Area cannot be Eligible New Large Loads.

(b) A New Large Load's Eligible New Large Load Amount shall be determined as follows:

(New Large Load's registered peak load (in MW), as provided in the Large Load Registry) minus (the sum of all BYONC arrangements with the New Large Load in accordance with Tariff, Attachment DD-4, section VII divided by the Forecast Pool Requirement for the first Delivery Year in which the BYONC cleared an RPM Auction, plus Allocated RBP UCAP MW assigned to the New Large Load, in accordance with Tariff, Attachment DD-4, section IX divided by the Forecast Pool Requirement for the first Delivery Year in which the Allocated RBP UCAP MW cleared an RPM Auction).

(c) For purposes of removing its eligibility to provide Interim Resource Adequacy Service, a New Large Load may enter into arrangements with BYONC supported by one or more resources.

VI. BRING YOUR OWN NEW CAPACITY CRITERIA

- (a) (i) Capacity Resources that cleared an RPM Auction for the first time in the Base Residual Auction for the 2027/2028, 2028/2029, and 2029/2030 Delivery Years may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below.
- (ii) Megawatts of Unforced Capacity that have not cleared an RPM Auction, other than those specified in subsection (a)(i) above, may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below. To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then megawatts of Unforced Capacity may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below and such megawatts (1) have not cleared in an RPM Auction conducted for a Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI.
- (iii) With the exception of the RPM Auctions listed in subsection (a)(i) above, to the extent megawatts of Unforced Capacity that have cleared an RPM Auction before any arrangement with a New Large Load based on such megawatts was reported to the Office of the Interconnection, then such megawatts of Unforced Capacity cannot qualify as BYONC even if the underlying resource meets the criteria in subsection (b) below.
- (b) To qualify as Bring Your Own New Capacity, resources must meet the following eligibility requirements:
- (i) For generation and storage resources, the resource must be supported by one of the following:
- (1) a new-build generation resource including new resources that obtain Capacity Interconnection Rights transferred from deactivated resources or resources that have announced deactivation as of April 10, 2026;
 - (2) the incremental capacity created by an uprate of Existing Generation Capacity Resources, but only to the extent such incremental capacity is created through an increase in such Generation Capacity Resource's installed capacity and increase in Capacity Interconnection Rights associated with that Generation Capacity Resource;
 - (3) the incremental capacity created by the utilization of Surplus Interconnection Service;
 - (4) repowering of a deactivated generation resource that deactivated prior to April 10, 2026; or

- (5) incremental capacity, whether due to greater Unforced Capacity or a higher level of Capacity Interconnection Rights, created by an Existing Generation Capacity Resource's changing fuel type to a more efficient fuel type.
- (ii) For Demand Resources or DER Capacity Aggregation Resources, the resource must qualify as a Planned Demand Resource or DER Capacity Aggregation Resource, as described in the RAA, Schedule 6 and Schedule 6.2 and:
- (1) be composed of, or reliant on, any location not registered in or prior to the 2026/2027 Delivery Year at which an incremental amount at that location is the result of the registration of new generation or storage assets at the location. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, any location registered in the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met; and/or
 - (2) be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for or prior to the 2026/2027 Delivery Year. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met.

VII. BRING YOUR OWN NEW CAPACITY ARRANGEMENTS WITH NEW LARGE LOADS

- (a) For any BYONC to be in an arrangement with a New Large Load,
 - (i) the Load Serving Entity serving the New Large Load or the applicable Electric Distributor shall report the BYONC in an arrangement with the New Large Load, in accordance with the PJM Manuals. The Office of the Interconnection may also accept information to the extent interconnection customers, Large Loads, Transmission Owners, or other entities voluntarily report any BYONC that may be in an arrangement with a New Large Load; and
 - (ii) the resource owner or entity with contractual authority to enter into a BYONC arrangement must certify to the Office of Interconnection, in accordance with the PJM Manuals, attesting to the arrangement with the New Large Load and that the BYONC will follow the requirements of Tariff, Attachment DD-4, section VIII.
- (b) For an arrangement between a New Large Load and BYONC to be effective for the 2027/2028 and 2028/2029 Delivery Years, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be met by April 1 for the first Delivery Year such arrangement is to result in a reduction in the New Large Load's Eligible New Large Load Amount. By April 15, the Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC.
- (c) For an arrangement between a New Large Load and BYONC to be effective for the 2029/2030 Delivery Year, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 50 days prior to the commencement of the 2029/2030 Base Residual Auction or by 30 days prior to the posting of the planning parameters for the Incremental Auctions arrangement for the 2029/2030 Delivery Year. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (d) For an arrangement between a New Large Load and BYONC to be effective for the 2030/2031 Delivery Year and subsequent Delivery Years, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 30 days prior to the posting of the planning parameters for the relevant RPM Auction for the initial Delivery Year the BYONC enters into an arrangement with the New Large Load. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (e) BYONC that is in an arrangement with a New Large Load must remain in such arrangement with that New Large Load unless and until the New Large Load is permanently out-of-service.
- (f) A physical resource may support multiple BYONC, each of which may be in an

arrangement with different New Large Loads, as long as no BYONC is in an arrangement with more than one New Large Load.

(g) A New Large Load may enter into an arrangement with discrete BYONC supported by different physical resources.

(h) A New Large Load may enter into an arrangement with BYONC in excess of its current Eligible Large Load Amount, e.g., to allow for expected growth in the New Large Load, and the full megawatt quantity of such BYONC shall be offered in the first RPM Auction for which the New Large Load is included in the Variable Resource Requirement Curve.

(i) (i) For any generation or storage resource, the Accredited UCAP of any BYONC shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load.

(ii) For Demand Resources or DER Capacity Aggregation Resources, the Accredited UCAP shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load and must be demonstrated each year for a 10-year period using the Demand Response or DER Capacity Aggregation Resources installed capacity for the first Delivery Year after the BYONC is in an arrangement with the New Large Load. For Demand Resources or DER Capacity Aggregation Resources that are also the actual New Large Load, there is no demonstration required for the initial Delivery Year only to not be an Eligible New Large Load.

VIII. BRING YOUR OWN NEW CAPACITY PARTICIPATION IN THE RELIABILITY PRICING MODEL

- (a) All BYONC in an arrangement with a New Large Load must meet the requirements in Tariff, Attachment DD, section 5.5A and become Capacity Resources eligible to participate in RPM Auctions.
- (b) All BYONC in an arrangement with a New Large Load must be offered into the RPM Auctions as Capacity Resources consistent with and pursuant to the capacity must-offer requirements and exceptions set forth in Tariff, Attachment DD, sections 6.6 and 6.6A. BYONC may not seek an exception to the capacity must-offer requirement to provide an external sale, as available under Tariff, Attachment DD, section 6.6(g) for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load.
- (c) All BYONC in an arrangement with a New Large Load and committed through RPM Auctions will be subject to all capacity market rules, as set forth in Tariff, Attachments DD and DD-1.
- (d) To the extent the resource supporting a BYONC arrangement is unavailable in a given Delivery Year, the seller of such resource will be subject to all relevant deficiency charges under Tariff, Attachment DD.
- (e) All BYONC in an arrangement with a New Large Load and not qualifying for an exception pursuant to Tariff, Attachment DD, section 6.6(g), must be offered into the applicable RPM Auctions as price takers, i.e., \$0/MW-day UCAP for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load. To the extent the resource is a Demand Resource or DER Capacity Aggregation Resource, the BYONC shall participate in RPM Auctions for ten (10) consecutive Delivery Years as an Annual Demand Resource or DER Capacity Aggregation Resource, as applicable; provided, however, the seller of such Demand Resource or DER Capacity Aggregation Resource may, in accordance with Tariff, Attachment DD-4, section VII(a)(i) report to the Office of the Interconnection BYONC that replaces such BYONC, where such replacement shall be for the remainder of the replaced BYONC's ten-year RPM Auction participation commitment and the replaced BYONC (and its supporting registrations) may no longer provide BYONC. In such event, the replacement BYONC would need to be supported by the certification required by Tariff, Attachment DD-4, section VII(a)(ii), and such replacement arrangement must be effective coincident with the initial BYONC releasing its arrangement.
- (f) To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then any existing BYONC are relieved of the obligations under this Tariff, Attachment DD-4, section VIII.

IX. ALLOCATION OF RBP UCAP MW

- (a) Each Electric Distributor zone/area allocated RBP Charges pursuant to Tariff, Attachment DD, section 18.3(a) shall be allocated RBP UCAP MW on a pro-rata basis using the Electric Distributor zone/area's assigned share of the total Final RBP Target MW across all zone/areas.
- (b) Each New Large Load's Allocated RBP UCAP MW shall be determined as follows:
 - (i) Each Electric Distributor allocated RBP UCAP MW shall inform the Office of the Interconnection how such RBP UCAP MW should be further allocated among the New Large Loads located in the Electric Distributor's zone/area; or
 - (ii) In the event the Electric Distributor has not informed the Office of the Interconnection how its RBP UCAP MW should be further allocated by April 1 before a given Delivery Year, the Office of the Interconnection shall allocate such RBP UCAP MW to the Electric Distributor's zone/area pro-rata among all New Large Loads located in the zone/area.
- (c) The Office of the Interconnection shall list in the Large Load Registry each New Large Load's Allocated RBP UCAP MW.

X. COMPENSATION FOR PROVIDING INTERIM RESOURCE ADEQUACY SERVICE

(a) The rate for the provision of Interim Resource Adequacy Service shall be 50% of the Non-Performance Charge Rate specified in Tariff, Attachment DD, section 10A(e), unless any Eligible New Large Load elects to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service as contemplated by Tariff, Attachment DD-4, section X(c). If any Eligible New Large Load so elects to accept less than 50% of the Non-Performance Charge Rate or waives in its entirety receipt of compensation for the provision of wholesale Interim Resource Adequacy Service, the wholesale rate for the provision of Interim Resource Adequacy Service shall reflect the accepted sum less than 50% of the Non-Performance Charge Rate or if compensation is waived entirely, the rate shall be zero dollars.

(b) (i) Following an Interim Resource Adequacy Event, unless the Electric Distributor informs the Office of the Interconnection otherwise in accordance with Tariff, Attachment DD-4, section X(b)(ii), the Electric Distributor shall be responsible for compensating all Eligible New Large Loads that provided Interim Resource Adequacy Service for up to the amount of such service provided. The Electric Distributor shall be responsible for charging customers in its zone/area to fund any such compensation.

(ii) The Electric Distributor may request the Office of the Interconnection to compensate certain Members for the provision of Interim Resource Adequacy Service and to assess charges on certain Load Serving Entities within the Electric Distributor's zone/area to fund such compensation. In support of such request, as further set forth in the PJM Manuals, the Electric Distributor shall (1) identify each Member to be compensated and provide the level of compensation and (2) identify each Load Serving Entity to be charged and the level of charge.

(iii) The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to pay any amounts owed to another party under this section. In the event the Electric Distributor requests the Office of the Interconnection facilitate the billing associated with an Interim Resource Adequacy Event, such billing shall be considered a bilateral transaction between the Electric Distributor and the identified Members and PJMSettlement shall not be a contracting party to the settlement.

(c) Nothing in this Tariff, Attachment DD-4, section X shall interfere with any Eligible New Large Load's election to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service.

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

“Accredited UCAP” shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

“Accredited UCAP Factor” shall mean, through the 2024/2025 Delivery Year, one minus EFORD, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource’s Accredited UCAP to the Capacity Resource’s installed capacity.

Agreement:

“Agreement” shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

“Annual Demand Resource” shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast

prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

“Applicable Regional Entity” shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

“Base Capacity Resource” shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

“Base Residual Auction” shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such

consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource or DER Capacity Aggregation Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall have the meaning provided in the Tariff.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and

deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on

such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

“Capacity Only Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

“Capacity Performance Resource” shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

“Capacity Resources” shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6; or (iv) generation and load reduction capability provided by a DER Capacity Aggregation Resource, pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.2 and the PJM Manuals.

Capacity Resource Provider:

“Capacity Resource Provider” shall mean a Member that (1) owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity; (2) or a DER Aggregator that has a contractual relationship to use a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource.

Capacity Storage Resource Class:

“Capacity Storage Resource Class” shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of (1) Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours or; (2) storage device Component DER. The characteristic duration of an Energy Storage Resource Class is the ratio of

the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

“Capacity Transfer Right” shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

“Coal Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

“Combination Resource” shall mean a Generation Capacity Resource, or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall have the same meaning as in the Tariff.

Complex Hybrid Class:

“Complex Hybrid Class” shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

DER Aggregator Officer Certification Form:

“DER Aggregator Officer Certification Form” shall mean a DER Aggregator’s certification as to an intended DER Capacity Aggregation Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

DER Capacity Aggregation Resource Sell Offer Plan:

“DER Capacity Aggregation Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of a DER Capacity Aggregation Resource in an RPM Auction, or an intended inclusion of a DER Capacity Aggregation Resource in an FRR Capacity Plan.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource that is a Generation Capacity Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Variable Resource and Combination Resource, that is an individual Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, the device’s maximum energy production capability, as defined by the resource’s state interconnection agreement; or (iii) for each Limited Duration Resource, the sustained level of output that the device can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

“ELCC Class” shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

“ELCC Class Rating” shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

“ELCC Class UCAP” shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

“ELCC Portfolio UCAP” shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

“ELCC Resource” shall mean a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

“ELCC Resource Performance Adjustment” shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the

average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

“Exigent Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing DER Capacity Aggregation Resource:

“Existing DER Capacity Aggregation Resource” shall mean a DER Capacity Aggregation Resource for which the DER Aggregator has identified existing Component DER that are registered in a DER Capacity Aggregation Resource for the current Delivery Year with PJM (even if not registered by such DER Aggregator) and that the DER Aggregator reasonably

expects to have under a contract to generate or reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such DER Capacity Aggregation Resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall have the meaning specified in the Tariff.

Firm Service Level:

“Firm Service Level” or “FSL” of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. “Firm Service Level” or “FSL” of Demand Resource shall mean the pre-determined level to which an end-use customer’s load shall be reduced, upon notification from the Curtailment Service Provider’s market operations center or its agent.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

“Fixed-Tilt Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

“Full Program Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

“Gas Combined Cycle Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

“Gas Combined Cycle Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

“Gas Combustion Turbine Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

“Gas Combustion Turbine Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

“Generation Capacity Resource” shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

“Hybrid Resource Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, the individual components would be in a Capacity Storage Resource Class, a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

“Hydropower With Non-Pumped Storage” shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation

Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

“Hydropower With Non-Pumped Storage Class” shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

- (i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and
- (ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

“Intermittent Hydropower Class” shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

“IOU” shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

“Intermittent Landfill Gas Class” shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load:

“Large Load” shall mean end-use customer(s) load that has a cumulative peak load of 50 megawatts or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site as further described in the PJM Manuals.

Large Load Adjustment:

“Large Load Adjustment” shall mean any MW quantity of adjustments to summer peak load at the “zone/area” level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a “zone/area” is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

Limited Demand Resource:

“Limited Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

“Limited Duration Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and

energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

“Nominal PRD Value” shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

“Non-Retail Behind the Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

“Nuclear Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

“Obligation Peak Load” shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

“Offshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The

characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

“Other Limited Duration Combination Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

“Other Unlimited Resource Class” shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

“Other Variable Resource Class” shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

“Peak Shaving Adjustment” shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

“Performance Assessment Interval” shall have the meaning specified in Tariff, Attachment DD.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Governing Agreements:

“PJM Governing Agreements” shall have the meaning provided in the Operating Agreement.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

“Planned Demand Resource” shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned DER Capacity Aggregation Resource:

A “Planned DER Capacity Aggregation Resource” shall mean any DER Capacity Aggregation Resource that does not currently have the capability to provide generation or reduction in demand, but that is scheduled to be capable of providing such generation or reduction in demand on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6.2. As set forth in Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1, a DER Aggregator submitting a DER Capacity Aggregation Resource Sell Offer Plan shall identify in such plan all DER Capacity Aggregation Resources in excess of those that qualify as Existing DER Capacity Aggregation Resources. A Planned DER Capacity Aggregation Resource must comply with all provisions of the DER Aggregator Participation Model described in Tariff, Attachment K-Appendix, section 1.4B and Operating Agreement, Schedule 1, section 1.4B, prior to the applicable Delivery Year.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the

Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has documentation which is functionally equivalent to an approved Decision Point I submission under the PJM Tariff Part VII or VIII as applicable or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to an approved Decision Point II submission under the PJM Tariff Part VII or VIII as applicable, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to a Generation Interconnection Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to be delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

"Planned Generation Capacity Resource" shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, Part VII or Part VIII, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, all the requirements for an approved Decision Point I submission have been met under Tariff Part VII or VIII (or, for resources for which a Decision Point I submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point I submission) prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, all the requirements for an approved Decision Point II submission have been met under Tariff Part VII or VIII (or, for resources for

which a Decision Point II submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point II submission) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) a Generation Interconnection Agreement or Wholesale Market Participation Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

“Portfolio Expected Unserved Energy” shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Performance Assessment Interval that triggers a PRD performance assessment or a Non-PAI Event, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example,

without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

“Tracking Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

“Unlimited Resource” shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

“Variable Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean the average of the Demand Resource customer’s specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

“Zone” or “Zonal” shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

“Zonal Winter Weather Adjustment Factor” or “ZWWAF” shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

7.8 Requirement to Designate Network Resources to Serve Capacity Needs for New Large Loads and Conditional Requirement to Provide Interim Resource Adequacy Service

Effective June 1, 2027, each LSE that desires to provide Network Transmission Service to support New Large Loads must designate one or more Generation Capacity Resources or Capacity Storage Resources that had not cleared an RPM Auction as Network Resource(s) in a cumulative amount that equals or exceeds the LSE's New Large Load's peak load (in MW) as reported in the Large Load Registry pursuant to RAA, Schedule 11 or such New Large Load may be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response. If, on June 1, 2027, an LSE has not so designated such Network Resource(s) as BYONC with which it has entered into an arrangement in accordance with this requirement and Tariff, Attachment DD-4, then the amount of New Large Load that is the difference between its reported peak load and its designated Bring Your Own New Capacity and assigned Allocated RBP UCAP MW will be subject to the rates, terms, and conditions of Interim Resource Adequacy Service, as set forth in Tariff, Attachment DD-4.

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources. An FRR Entity may not include in its FRR Capacity Plan any MW quantity of Existing Generation Capacity Resource in excess of what such FRR Entity owned or contracted by such FRR Entity prior to June 1, 2027, to serve New Large Load.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the Base Zonal FRR Scaling Factor times the summation of the FRR Entity's MW share of the Zonal Weather Normalized Summer Peak last determined prior to the Base Residual Auction for such Delivery Year plus the Obligation Peak Load MW associated with any Load Adjustment specified for such Delivery Year for any "zone/area" served by the FRR Entity's Capacity Plan. The Obligation Peak Load MW associated with a Load Adjustment specified for a "zonal/area" is determined as set forth in RAA, Schedule 8, section B.

The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand

must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal $[(ZPLDY - ZLA) / ZWNSP]$, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year;

ZLA = the Zonal MW quantity of Load Adjustment for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM

Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, an FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region (“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), or Mid-Atlantic Region (“MAR”), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in \$/MW-day, times the shortfall of

Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in \$/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

SCHEDULE 11

DATA SUBMITTALS

A. To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.
2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.
3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.
4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

B. 1. (a) Each Party shall submit, or cause to be submitted, to the Office of the Interconnection the following information, as may be further described in the PJM Manuals, related to each Large Load served by the Party:

- Eligible Customer/Network Customer for Large Load;
- Description of Large Load;
- Location(s) (Control Zone, Electric Distributor zone/area, where a zone/area is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering);
- In-service date for each increment of load;
- Peak shaving adjustment value pursuant to a state program codified in state law and whether and how it meets the requirements of Tariff, Attachment DD-2;
- Delivery point / Point(s) of interconnection (include all if more than one);
- Peak load quantity (MW) and ramp schedule, if applicable;

- Telemetry specifications;
- BYONC quantity (MW) and ramp schedule, if applicable;
- Allocated RBP UCAP MW quantity (MW), if applicable;
- Backup generation (MW), including fuel type and relevant permitting limitations;
- Contracts or service agreements between the Large Load and the LSE;
- Points of contact at the applicable Transmission Owner, Electric Distributor, and Load Serving Entity;
- EMS B1/B2/B3 name (for the applicable Transmission Owner, Electric Distributor); and
- Additional details and contents as necessary, in accordance with the PJM Manuals.

(b) The Parties acknowledge that information related to the development and maintenance of the Large Load Registry may be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement and the Tariff.

(c) The Office of the Interconnection may review information and coordinate with the applicable Transmission Owner and Electric Distributor as needed, regarding the validity of the information provided, including through requesting additional information as the Office of the Interconnection deems necessary, as further set forth in the PJM Manuals. The Office of the Interconnection also may consult with the Large Load.

(d) Based on the information provided, or caused to be provided, by each Party, as well as other information provided by, for example, Electric Distributors, the Office of the Interconnection shall maintain a registry of all Large Loads, and update it periodically. To the extent such documents, data, or other information provided to the Office of the Interconnection has been designated as confidential by a Party, Electric Distributor, or other entity supplying the information, the Office of the Interconnection shall maintain the confidentiality of the information provided under this RAA, Schedule 11, section B consistent with its obligations under Operating Agreement, section 18.17. Information maintained in the Large Load registry may be available to Authorized Commissions, Transmission Owners, Electric Distributors, Load Serving Entities, the Market Monitoring Unit, and FERC subject to appropriate data protection safeguards required by Operating Agreement, section 18.17.

(e) The Office of the Interconnection shall post aggregate data from the Large Load Registry on the PJM website, aggregated by Electric Distributor zone/area, where possible and in a manner consistent with existing confidentiality protections in the PJM Governing Agreements.

2. (a) Each Party serving or contracted to serve a Large Load that is or will be in service prior to June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection by March 1, 2027.

(b) Each Party serving or contracted to serve a New Large Load that will be in service on or after June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection before the in-service date of the Large Load.

(c) Each Party contracted to serve a New Large Load shall provide the location(s) as required by RAA, Schedule 11.B.1 to the Office of the Interconnection before determination of the final PJM Regional Peak Load Forecast for the effective RPM Auction for the Delivery Year in which the New Large Load is expected to be in-service starting with the 2028 PJM Regional Peak Load Forecast.

Each Party shall promptly inform the Office of the Interconnection of any change in the information required by RAA, Schedule 11.B.1 with respect to a Large Load served by the Party, including whether the Party no longer serves the Large Load or has acquired the contractual right to serve a registered Large Load.

3. The information provided pursuant to RAA, Schedule 11, section B will be used, to the extent necessary, for purposes including but not limited to implementation of Interim Resource Adequacy Service, which is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that have not entered into an arrangement with new capacity additions to the PJM Region, as more fully set forth in Tariff, Attachment DD-4.

Attachment C

Affidavit of Christopher Pilon on
Behalf of PJM Interconnection, L.L.C.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.	)	
	)	Docket No. ER26-____-000
	)	

**AFFIDAVIT OF CHRISTOPHER PILONG
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

I. Introduction

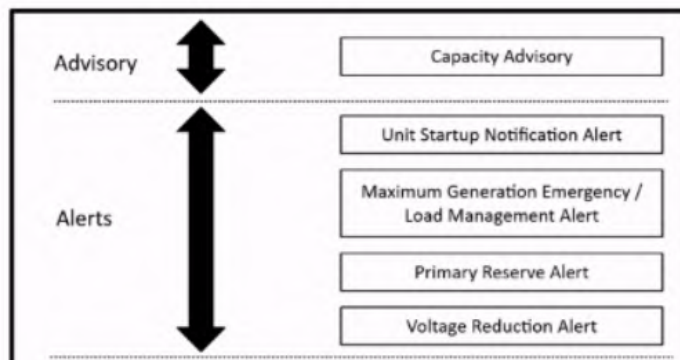
1. My name is Christopher Pilon. My business address is 2750 Monroe Boulevard, Audubon, Pennsylvania, 19403. I am Senior Director of Operations Planning for PJM Interconnection, L.L.C. (“PJM”). I am submitting this affidavit on behalf of PJM to discuss when and how PJM would utilize the Interim Resource Adequacy Service (“IRAS”) to manage system reliability. Specifically, in this affidavit, I explain how PJM will generally follow its existing processes and procedures in calling for IRAS load reductions and provide some examples of how it will work in practice.
2. I joined PJM in November 2001. Currently, as Senior Director of Operations Planning, I am responsible for the Transmission Operations Department, Generation Department, Transmission Service Department, and Outage Analysis Technologies Department. These departments perform near-term transmission outage analysis and approvals, generation outage analysis and approvals, facilitate annual Black Start Unit commitments, support and develop operational tools, implement and comply with all North American Energy Standards Board business rules regarding Available Flowgate Capability/Available Transfer Capability, perform gas-electric coordination activities, as well as many other tasks to prepare for, and support, real time operations. The teams also perform seasonal reliability assessments, support the various tools and applications utilized in these processes, and coordinate directly with the Market Services Division and System Planning Division.
3. Previously, as Director, Dispatch, I was responsible for the oversight and operation of the Valley Forge and Milford Control Centers. This function included ensuring the reliable operation of the power grid, in accordance with all PJM and North American Electric Reliability Corporation (“NERC”) reliability standards pertaining to the functions of Reliability Coordinator, Balancing Authority, and Transmission Operator. In addition, I was responsible for ensuring the efficient economic dispatch of the system under the existing PJM market rules and neighboring Joint Operating Agreements.
4. Prior to that position, I served as a Reliability Engineer and then Manager – Reliability Engineering. As Manager for the Reliability Engineering Group, I managed the group responsible for coordinating day-ahead and real-time operating plans among PJM staff, PJM Transmission Owners, PJM Generation Owners, and our neighboring entities. I performed these functions directly in my earlier role as a Reliability Engineer. I hold a

Bachelor of Science degree in Electrical Engineering from Lehigh University and a Master of Business Administration degree from Villanova University.

II. Overview of Practices When Capacity Shortages Give Rise to Emergency Procedures

5. As set forth in section 2.1 of PJM Manual 13, “PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM [regional transmission organization (“RTO”)] or in any other Control Area that is interconnected directly or indirectly with the PJM RTO.”^{1,2}
6. In PJM, there are three general levels of Emergency Procedures for capacity shortages, and an advisory level.
7. Prior to the Operating Day, PJM may issue advisories and/or alerts (see Figure 1, below). The advisory level is general in nature and for elevated awareness “only and may be issued one or more days in advance of the Operating Day.”³ Emergency Procedure Alerts may be “issued one or more days in advance of the Operating Day for elevated awareness and to give time for advanced preparations.”⁴

Figure 1: Advisory and Alerts⁵



A. Steps in Real-Time Prior to Emergency Actions

8. PJM Dispatchers monitor projected and current reserves and determine whether actions are needed to maintain reserves within the required limits. In accordance with PJM Manual 13, before entering into capacity-related emergency actions in real-time, PJM Dispatch will

² Systems Operations Division, *PJM Manual 13: Emergency Operations*, PJM Interconnection, L.L.C., section 2.1 (rev. 98, June 24, 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf> [<https://perma.cc/HE9Y-BNQK>] (“PJM Manual 13”).

³ PJM Manual 13, section 2.3.

⁴ PJM Manual 13, section 2.3.

⁵ PJM Manual 13, section 2.3.

use available generation and economic demand response, based on economic dispatch, which ensures that Real-Time Locational Marginal Prices reflect actual system conditions.⁶

9. Second, as set forth in PJM Manual 13, if generation and economic demand resources are not sufficient to maintain reserves, PJM Dispatch will then recall energy from its Capacity Resources by curtailing non-firm export transactions, i.e., interchange transactions, in accordance with Part II of the PJM Open Access Transmission Tariff (“Tariff”).
10. PJM Dispatch will also have declared a NERC Energy Emergency Alert Level 1 (“EEA1”), as required by NERC Standard EOP-011 Attachment 1, via the Reliability Coordinator Information System and Emergency Procedures webpage.⁷
11. There are three levels of NERC Energy Emergency Alert Levels (EEA1 through EEA3), with an EEA3 being the highest alert level. “EEA1 signals that PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.”⁸ “An EEA3 is issued when [PJM] is unable to meet minimum Contingency Reserve Requirements.”⁹
12. Third, if system conditions remain constrained and reserves are projected to be short of requirements, assuming PJM’s new, yet-to-be-effective transmission service products—Non-Firm Contract Demand Service (“CDS”) and Interim Network Integrated Transmission Service (“Interim NITS”) are effective, PJM may direct curtailment of Non-Firm CDS and/or Interim NITS transmission service.¹⁰
13. Fourth, if system conditions remain constrained and reserves are projected to be short of requirements, then PJM will curtail the new IRAS load as outlined in the Examples below.
14. Fifth, if a system emergency develops, then PJM will initiate Steps 1 through Step 10 of the Capacity Emergency procedures as necessary to maintain the reliability of the grid. If Step 10 (Manual Load Dump Action) is reached, this may require firm load to shed pursuant to emergency actions. PJM members are expected to implement all emergency procedures based on the timeliness associated with each specific procedure.¹¹

⁶ PJM Manual 13, section 2.3.2.

⁷ PJM Manual 13, section 2.3.2.

⁸ PJM Manual 13, section 2.3.1.

⁹ PJM Manual 13, section 2.3.2.

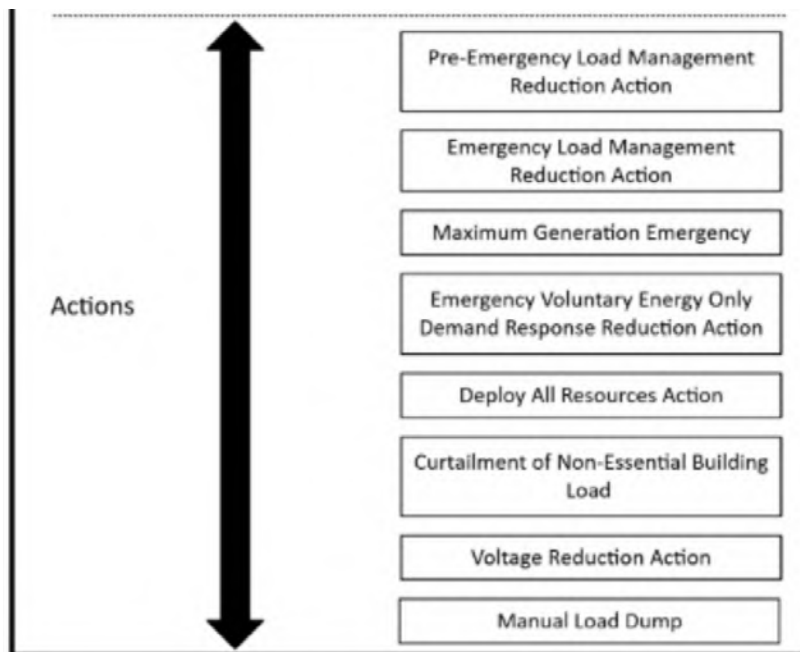
¹⁰ *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,209, at P 551 (2026) (“[W]e find PJM’s proposal to curtail Interim NITS and [Non-Firm Contract Demand] transmission service prior to deployment of its Pre-Emergency Load Response Program, or in response to a transfer capability shortage as a result of system reliability conditions, to be just and reasonable because it is consistent with how Non-Firm [Point-to-Point Service] is curtailed. . . . [W]e find that PJM’s proposal to curtail Interim NITS during capacity or reserve shortages is just and reasonable and consistent with both the nature of the transmission service as a non-firm transmission service for which Eligible Customers do not pay generation capacity charges, and the need to maintain reliability.” (footnote omitted)).

¹¹ PJM Manual 13, section 2.3.

B. Steps for Real-Time Emergency Actions Set Forth in PJM Manual 13

15. Importantly, while there is a sequence of escalating emergency action steps set forth in PJM Manual 13, the rapidness of system events influences the timing and order of actions necessary to maintain system reliability. Therefore, PJM Dispatchers “have the flexibility to implement emergency procedures in whatever order is required to ensure system reliability.”¹² Likewise, they have the flexibility to exit emergency procedures in a different order than they were implemented.”¹³
16. Figure 2, below, excerpted from PJM Manual 13, illustrates the escalating emergency actions that PJM may take and/or require of Members under the status quo rules.¹⁴

Figure 2.



17. As Figure 2, above, demonstrates, under current Emergency Procedures, the first step when an emergency action is declared is to require Pre-Emergency Load Management Reductions, which essentially require a class of Demand Resources and DER Aggregation Resources to reduce load.
18. At the most extreme, PJM will declare an EEA3, in which PJM may call for a Manual Load Dump (i.e., shedding load taking NITS), a last-resort emergency instruction issued by PJM, triggered during severe capacity deficiencies or critical transmission overloads when all other operational steps have failed.

¹² PJM Manual 13, section 2.3.

¹³ PJM Manual 13, section 2.3.

¹⁴ PJM Manual 13, section 2.3.

III. Addition of Interim Resource Adequacy Service Emergency Procedures to Existing Emergency Procedures in PJM Manual 13

19. New Large Loads are developing more quickly than generation and transmission can be built. As a result, this may impact the ability for PJM to maintain a reliable system and continue to meet the demand for existing customers and maintain reserve requirements during times of peak demand and/or significant generator outages. Therefore, a new operational tool is needed to ensure the current level of reliability for our customers is maintained.
20. IRAS, as proposed, is an additional load reduction service that PJM may deploy in real-time, starting with the 2027/2028 Delivery Year. As part of this filing, PJM is proposing a new term, “Interim Resource Adequacy Service Action,” to mean “an Operating Instruction, as defined by NERC, issued from the Office of the Interconnection to reduce load prior to calling on Pre-Emergency Load Management Reductions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits (“IROL”) within prescribed limits and prevent cascading outages.”¹⁵
21. The IRAS framework is intended to operate as both a forward-looking reliability assurance mechanism and an operational tool. The identification of an IRAS requirement for each Electric Distributor’s zone/area establishes the reliability obligation applicable to affected load, while PJM’s real-time operating processes determine when and how that obligation is activated based on actual system conditions.
22. The IRAS framework therefore does not require PJM to reduce affected load whenever an IRAS requirement exists. Rather, the IRAS requirement establishes an operational reliability resource available to PJM, which can be called upon when actual system conditions indicate that the reliability need addressed by the IRAS requirement is materializing.
23. PJM will incorporate IRAS-designated load, that PJM will determine under the IRAS rules, into its operating models, operating plans, and real-time reliability assessments. PJM’s existing real-time Energy Management System and contingency-analysis processes provide the platform for evaluating system conditions and identifying potential reliability violations.
24. If the proposed IRAS framework is accepted by the Commission, PJM Manual 13 will be revised to establish the specific details of how PJM will deploy IRAS through new Emergency Procedures, i.e., Emergency Alerts, Actions, Advisories, and/or Warnings. As is the norm, PJM will work with stakeholders to revise PJM Manual 13 to establish specific language for IRAS Emergency Procedures after the IRAS proposal has been filed with the

¹⁵ Tariff, Definitions – Interconnection Reliability Operating Limits; *Glossary Terms*, North American Electric Reliability Corporation, <https://www.nerc.com/glossary-of-terms?alpha=I> [<https://perma.cc/TZ9W-MZ4K>] (last visited Aug. 11, 2026) (defining Interconnection Reliability Operating Limit as “[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.”).

Commission. Any revisions to PJM Manual 13 to reflect IRAS will not become effective unless the Commission accepts the IRAS framework.

25. That said, I will provide, below, a general overview of how IRAS, as a new operational tool, will be deployed. PJM expects that existing Emergency Procedures set forth in PJM Manual 13 will not change except to add IRAS as another potential tool at PJM's disposal that PJM may deploy in efforts to address a potential emergency prior to Pre-Emergency Load Management Reduction Action.
26. In day-ahead, Interim Resource Adequacy Service Alerts may precede a Maximum Generation Alert ("Max Gen Alert"). Thus, IRAS provides a new, lower-level Emergency Procedure Alert that PJM Dispatch may issue prior to a Max Gen Alert. In real-time, PJM Dispatch will deploy Interim Resource Adequacy Service Actions before Pre-Emergency Load Management Reduction Actions. Thus, in real-time, IRAS provides a new step, at PJM's disposal, prior to impacting existing customers. If the Interim Resource Adequacy Service Actions do not address the emergency, PJM Dispatchers would then take necessary Pre-Emergency Load Management Reduction Actions and declare escalating Emergency Procedures as necessary.
27. In the next subsections of my affidavit, I explain how a PJM Dispatcher may deploy IRAS. In Example 1, below, I describe how PJM issues an Interim Resource Adequacy Service Alert in the day-ahead. In Example 2, I describe a scenario when, in real-time, PJM experiences an RTO-wide reliability and/or capacity shortfall event and responds by deploying IRAS. In Example 3, in real-time, PJM experiences an IROL and responds by deploying IRAS.
28. It is important to note that prior to the start of each Delivery Year, the megawatts ("MW") quantity of IRAS that will be required to respond to an Interim Resource Adequacy Service Alert will be determined by PJM for each Electric Distributor zone/area. This value will be utilized by PJM Dispatch in their system projections, alerts and actions in the examples below (e.g., PJM may determine, for example, that prior to the Delivery Year, there may be 4 gigawatts of IRAS available across the RTO, with smaller amounts assigned to an Electric Distributor zone/area for real-time curtailment if an Interim Resource Adequacy Service Action is issued).

A. Example 1—Day-Ahead Interim Resource Adequacy Service Alert

29. As PJM operators look ahead to the next Operating Day, they periodically evaluate forecasted demand and scheduled supply. They also evaluate, among many other things, expected weather conditions to determine, e.g., wind and solar resource availability, temperature, etc. PJM schedules reserves on a day-ahead basis to address such contingencies and variabilities.
30. In this example, in day-ahead, PJM operators reasonably expect that insufficient supply will be available to meet expected real-time demand and reserves for the next Operating Day. PJM's operators will have available to them, on a daily basis, the expected aggregate amount of Interim Resource Adequacy Service MW that can be reduced at the Electric

Distributor level. If reduction of some/all of the IRAS load may be necessary to meet real-time demand and reserve requirements, PJM Dispatchers may elect to issue an Interim Resource Adequacy Service Alert in day-ahead.

31. PJM issues an Interim Resource Adequacy Service Alert before and/or concurrently with a Max Gen Alert/Load Management Alert. The Interim Resource Adequacy Service Alert puts all Eligible New Large Loads on notice that PJM could request reductions in load in quantities equal to or lesser than each Electric Distributor zone/area's assigned IRAS amounts during the next Operating Day. However, under an alert, no IRAS reduction is actually requested or implemented. This is simply a notice to prepare and will be issued to provide maximum notice possible.
32. In this example, PJM also elects to issue a Max Gen Alert/Load Management Alert in day-ahead.
33. As explained in section 2.3.1 of PJM Manual 13, "The intent of the alert(s) is to keep all affected system personnel aware of the forecasted and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the ALLCALL system and posted to selected PJM websites to assure that all members receive the same information. Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages."¹⁶
34. For Examples 2-3, where PJM issues an Interim Resource Adequacy Service Action in real-time, it can be assumed that PJM Dispatch would have already issued an Interim Resource Adequacy Service Alert. Thus, in real-time, PJM's members are already aware that potential Emergency Procedure actions may take place in real-time. However, it should be noted that not all conditions can be forecasted, and it is not a requirement that an Interim Resource Adequacy Service Alert be issued prior to an Interim Resource Adequacy Service Action. Therefore, it is possible to have no day-ahead alerts, but nevertheless have an Interim Resource Adequacy Service Action or other Actions issued during the Operating Day.

B. Example 2—Real-Time Interim Resource Adequacy Service Action, RTO-Wide Emergency

35. In real-time, PJM faces an RTO-wide system emergency. Prior to directing an Interim Resource Adequacy Service Action, however, PJM has several other ways to address RTO-wide reliability concerns.
36. First, in keeping with the practice in place today and set forth in PJM Manual 13, PJM Dispatchers deploy available generation and economic demand resources, in economic dispatch order while maintaining required reserves. Even with all available economic resources dispatched, PJM's operators may still face a potential reliability issue and capacity shortfall in real-time.

¹⁶ PJM Manual 13, section 2.3.1.

37. Second, in keeping with the practice in place today and as set forth in PJM Manual 13, if issues persist or are projected to deteriorate, PJM operators may require non-firm interchange transaction curtailment, as needed.
38. PJM Dispatchers will have already issued an EEA1. After the first and second steps taken by PJM Dispatchers, PJM remains under an EEA1.
39. Third, assuming for purposes of this example that the yet-to-be-effective Interim NITS and Non-Firm CDS transmission services are now in place, PJM may curtail Non-Firm CDS, followed by Interim NITS.
40. Fourth, after all non-firm transmission services are curtailed, PJM Dispatchers would then issue the new Interim Resource Adequacy Service Action prior to deployment of a Pre-Emergency Load Management Reduction Action.
41. PJM intends to issue an Interim Resource Adequacy Service Action through the status quo notification processes set forth in PJM Manual 13.¹⁷ Pursuant to the Interim Resource Adequacy Service Action, PJM prioritizes load reduction from those Electric Distributor zones/areas where New Large Loads have not brought their own new capacity and do not have Allocated Reliability Backstop Procurement Unforced Capacity Megawatts (“RBP UCAP MW”) sufficient to cover their capacity needs. PJM’s operators will direct the IRAS reduction to Electric Distributor zones/areas as needed based on system conditions.
42. More specifically, through an Interim Resource Adequacy Service Action, PJM Dispatchers will direct Electric Distributors to implement reductions in load up to, and capped at, the pre-Delivery Year IRAS obligations they were assigned. Importantly, PJM will not direct specific New Large Loads to reduce load, even though Electric Distributors—in coordination, where applicable, with relevant states, Load Serving Entities, and New Large Loads—may issue more specific directives to specific retail customers.¹⁸ PJM will only direct load reduction of an aggregate MW IRAS within the zone or area.
43. In this example, the Interim Resource Adequacy Service Action is deployed in response to a Region-wide emergency. As such, based on the maximum IRAS amounts assigned to each Electric Distributor zone/area, PJM Dispatchers call for some or all Electric Distributors to reduce load across the PJM RTO Region in the manner they see fit to

¹⁷ System Operations Division, *PJM Manual 37: Reliability Coordination*, PJM Interconnection, L.L.C., section 3.2 (rev. 23 Apr. 22, 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m37.pdf> [<https://perma.cc/FY3P-8SCM>].

¹⁸ As PJM Manual 13 notes, PJM members have Member Load shed plans, which, among other things, “recognize priority and critical load including: Essential health and public safety facilities such as hospitals, police, fire facilities, 911 facilities, wastewater treatment facilities; Facilities providing electric service to facilities associated with Bulk Electric System including off-site power to generating stations, substation light and power; Critical natural gas infrastructure used to supply gas pipeline pumping plants, processing and production facilities; and Telecommunication facilities.” PJM Manual 13, section 2.3.2.

address the system conditions. As directed by PJM, those Electric Distributors then reduce load in accordance with PJM's emergency action.

44. Figure 3, below, shows how an Interim Resource Adequacy Service Action fits into PJM's existing Emergency Procedures framework.

Figure 3: PJM Emergency Procedures with Interim Resource Adequacy Service (IRAS)



45. As shown in Figure 3, the Interim Resource Adequacy Service Action precedes Pre-Emergency Load Management Reductions in PJM's order of operations to maintain reliability.
46. In this example, the EEA1 continues, and PJM Dispatchers then proceed to Pre-Emergency Load Management Reductions, in keeping with the status quo steps set forth in PJM Manual 13.¹⁹
47. The Pre-Emergency Load Management Reductions address the RTO-wide emergency. PJM Dispatch cancels the Pre-Emergency Load Management Reductions and Interim Resource Adequacy Service Actions, when appropriate.

C. Example 3—Real-Time Interim Resource Adequacy Service Action, Potential Interconnection Reliability Operating Limit Violation

48. In my next real-time example, there is a potential IROL violation. Certain facilities, known as IROL facilities, can significantly impact system reliability if loaded above a designated limit.²⁰ If an IROL facility's designated limits are exceeded, this has the potential to result

¹⁹ System Operations Division, *PJM Manual 37: Reliability Coordination*, PJM Interconnection, L.L.C., section 3.2, (rev. 23 Apr. 22, 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m37.pdf> [<https://perma.cc/FY3P-8SCM>].

²⁰ PJM Manual 13, section 5.5 (including identification of IROL facilities).

in wide-area voltage collapse.²¹ Therefore, PJM Dispatch must quickly act to mitigate IROL violations.

49. An IROL violation, unlike a PJM RTO-wide emergency, occurs when one or more IROL facilities between zones become overloaded or is otherwise experiencing zonal capacity shortages. In my example, PJM's response to a potential IROL violation includes issuance of an Interim Resource Adequacy Service Action.
50. PJM monitors potential IROL violations via PJM Energy Management System, which automatically identifies zones and loads that are at risk of triggering IROL facilities to exceed their limits.
51. In the event of a potential IROL violation, PJM engages in similar steps and notifications in real-time described in Example 2, above, but does so in a more targeted manner. For example, the response to the potential IROL violation may not require curtailment of all non-firm exports to the extent the exports do not exacerbate the potential IROL violation.
52. In this case, for example, let's say the Dominion Zone is experiencing a transmission capacity scarcity event resulting from a potential IROL violation due to overloading of an IROL facility in West Virginia, e.g., AP South. In response, it makes little sense for PJM Dispatchers to curtail non-firm exports to the West or North of the PJM system. However, PJM may require curtailment of non-firm exports between PJM and areas to the South that are flowing power across the AP South IROL Reactive Interface to mediate the potential IROL violation.
53. Similarly, when PJM Dispatchers issue an Interim Resource Adequacy Service Action in response to the potential IROL violation, it is a more targeted Interim Resource Adequacy Service Action than the pro-rata load reductions across multiple Electric Distributor zones/areas issued in Example 2, above. If load in a particular Electric Distributor zone/area is not negatively impacting transmission flows into the Dominion Zone, load reduction in that zone/area may not have any effect on the Dominion Zone.
54. The Interim Resource Adequacy Service Action, in the event of an IROL violation, will require similar steps in real-time as an Interim Resource Adequacy Service Action across the entire PJM RTO Region, except that PJM Dispatchers will only deploy load reductions up to the maximum IRAS amounts PJM determined for those affected Electric Distributors' zones/areas needed to alleviate the transmission capacity scarcity event within that specific zone/area.
55. Through distribution factor modeling from its Energy Management System, PJM will identify the Electric Distributors' zone(s)/area(s) in which an Interim Resource Adequacy Service Action will have the greatest impact in alleviating the IROL violation. PJM will then direct those relevant Electric Distributors to reduce load. The Electric Distributor, in

²¹ System Operations Division, *PJM Manual 37: Reliability Coordination*, PJM Interconnection, L.L.C., section 3.2, (rev. 23Apr. 22, 2026), <https://www.pjm.com/-/media/DotCom/documents/manuals/m37.pdf> [<https://perma.cc/FY3P-8SCM>].

coordination with applicable states, Load Serving Entities, and Large Loads, will, in turn, direct specific loads to reduce in response to the Interim Resource Adequacy Service Action.

56. This concludes my affidavit.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C.

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)
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Docket No. ER26-____-000

VERIFICATION

I, **Christopher Pilon**, state, under penalty of perjury, that I am the Christopher Pilon referred to in the foregoing document entitled, "Affidavit of Christopher Pilon on Behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Christopher Pilon
Christopher Pilon

FERC rendition of the electronically filed tariff records in Docket No. ER26-03515-000**Filing Data:**

CID	Filing Title	Company Filing Identifier	Type of Filing Code	Associated Filing Identifier
C000030	Proposal to Establish Interim Resource Adequacy Service & a Large Load Registry	11543	10	
	Tariff Title	Tariff ID	Payment Confirmation	Suspension Motion
	Intra-PJM Tariffs	23		

Tariff Record Data:

Record Content Description	A-B
Tariff Record Title	OATT Definitions - A - B
Record Version Number	25.0.0
Option Code	A
Record Narrative Name	Definitions - A - B
Tariff Record ID	4
Tariff Record Collation Value	3145309
Tariff Record Parent Identifier	3
Proposed Date	2026-10-12
Priority Order	1260
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

Definitions – A - B**30-minute Reserve:**

“30-minute Reserve” shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

“30-minute Reserve Requirement” shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

“Abnormal Condition” shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

“Acceleration Request” shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Affected System:

“Affected System” shall mean an electric system other than the Transmission Provider’s Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

“Affected System Operator” shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

“Affiliate” shall mean any two or more entities, one of which Controls the other or that are under common Control. “Control,” as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity’s board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

“Agreements” shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Allocated RBP UCAP MW:

“Allocated RBP UCAP MW” shall mean the RBP UCAP MW allocated to a New Large Load in accordance with Tariff, Attachment DD-4, section IX.

Ambient-Adjusted Rating:

“Ambient-Adjusted Rating” (AAR) shall mean a Transmission Facility Rating that:

- (a) Applies to a time period of not greater than one hour.
- (b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.
- (c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.
- (d) Is evaluated at least each hour, if not more frequently.

Ancillary Services:

“Ancillary Services” shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider’s Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

“Annual Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

“Annual Resource” shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Resource Price Adder:

“Annual Resource Price Adder” shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:

“Annual Revenue Rate” shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

“Annual Transmission Costs” shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

“Applicable Laws and Regulations” shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

“Applicable Regional Entity” shall mean the Regional Entity for the region in which a Network

Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

“Applicable Standards” shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

“Applicable Technical Requirements and Standards” shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, “Applicable Technical Requirements and Standards” shall refer to the “PJM Small Generator Interconnection Applicable Technical Requirements and Standards.” All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider’s internet website.

Applicant:

“Applicant” shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

“Application” shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

“Attachment Facilities” shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

“Attachment H” shall refer collectively to the Attachments to the PJM Tariff with the prefix “H” that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

“Auction Revenue Rights” or “ARRs” shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

“Auction Revenue Rights Credits” shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

“Authorized Government Agency” means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

“Avoidable Cost Rate” shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

“Balancing Congestion Charges” shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

“Balancing Ratio” shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

“Base Capacity Demand Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:

“Base Capacity Demand Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:

“Base Capacity Resource” shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:

“Base Capacity Resource Constraint” for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORD] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:

“Base Capacity Resource Price Decrement” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Load Generation Resource

“Base Load Generation Resource” shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

“Base Offer Segment” shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

“Base Residual Auction” shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

“Batch Load Economic Load Response Participant Resource” shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such

generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall mean megawatts of Unforced Capacity that meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI. Megawatts of Unforced Capacity that have been previously included in an FRR Capacity Plan prior to the 2027/2028 Delivery Year do not qualify as BYONC. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then BYONC that has been included previously in an FRR Capacity Plan prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI do not qualify as BYONC.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Tariff Record Data:

Record Content Description	E-F
Tariff Record Title	OATT Definitions - E - F
Record Version Number	46.0.0
Option Code	A
Record Narrative Name	Definitions - E - F
Tariff Record ID	6
Tariff Record Collation Value	4575515
Tariff Record Parent Identifier	3
Proposed Date	2026-10-12
Priority Order	1420
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

Definitions – E - F**Economic-based Enhancement or Expansion:**

“Economic-based Enhancement or Expansion” shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

“Economic Load Response Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Load Response Regulation Only Participant:

“Economic Load Response Regulation Only Participant” shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, and is only eligible to participate in the PJM Regulation market.

Economic Maximum:

“Economic Maximum” shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

“Economic Minimum” shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

“Effective FTR Holder” shall mean:

- (i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or
- (ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORD:

“EFORD” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

“Electrical Distance” shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

“Eligible Customer” shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

“Eligible Fast-Start Resource” shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Eligible New Large Loads:

“Eligible New Large Loads” shall mean a New Large Load eligible to provide Interim Resource Adequacy Service in accordance with Tariff, Attachment DD-4, section V.

Eligible New Large Load Amount:

“Eligible New Large Load Amount” shall mean the total megawatt value of load an Eligible New Large Load may be required to make available for Interim Resource Adequacy Service in an Electric Distributor zone/area.

Emergency Action:

“Emergency Action” shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

“Emergency Condition” shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

“Emergency Load Response Program” shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when

dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Market Opportunity Cost:

“Energy Market Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has an operational limitation due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

“Energy Resource” shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

“Energy Settlement Area” shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

“Energy Storage Resource” shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

“Energy Storage Resource Model Participant” shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

“Energy Storage Resource Participation Model” shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

“Energy Transmission Injection Rights” shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

“Entity Providing Supply Services to Default Retail Service Provider” shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

“Environmental Laws” shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

“Environmentally-Limited Resource” shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

“Equivalent Load” shall mean the sum of a Market Participant’s net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

“Event of Default,” as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Excluded LDA New Large Load Amounts:

“Excluded LDA New Large Load Amounts” shall mean, converted in UCAP terms by estimating the impact on required imports to a Locational Deliverability Area and exclusive of

any load in an FRR Service Area, [the sum of all New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast for the relevant Delivery Year] minus [New Large Loads in the relevant Locational Deliverability Area that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the Locational Deliverability Area or (ii) assigned Allocated RBP UCAP MW in Locational Deliverability Area].

Excluded RTO New Large Load Amounts

“Excluded RTO New Large Load Amounts” shall mean, converted in UCAP terms by using the Forecast Pool Requirement and exclusive of any load in an FRR Service Area, [the sum of all New Large Loads across the PJM Region in the load forecast for the relevant Delivery Year] minus [New Large Loads across the PJM Region that were included in the load forecast used for the 2028/2029 Delivery Year] minus [the total MW quantity of New Large Load that is added on or after the 2029/2030 Delivery Year and is (i) in an arrangement with BYONC in the RTO or (ii) assigned Allocated RBP UCAP MW in the RTO].

Exercise of Buyer-Side Market Power:

“Exercise of Buyer-Side Market Power” shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller’s (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

“Export Credit Exposure” is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant’s Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

“Export Nodal Reference Price” at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time

periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

“Export Transaction” shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

“Export Transaction Price Factor” for a prospective time interval shall be the greater of (i) PJM’s forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction’s dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

“Export Transaction Screening” shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

“Export Transactions Net Activity” shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

“Extended Primary Reserve Requirement” shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

“Extended Synchronized Reserve Requirement” shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

“Extended 30-minute Reserve Requirement” shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

“External Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

“External Resource” shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

“Facilities Study” shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider’s Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider’s Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer’s New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

“Fast-Start Resource” shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

“Federal Power Act” shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

“Final Offer” shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

“Final RTO Unforced Capacity Obligation” shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

“Financial Close” shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

“Financial Default” shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an

invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

“Financial Transmission Right” or “FTR” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

“Financial Transmission Right Obligation” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

“Financial Transmission Right Option” shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

“Firm Transmission Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

“Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

“First Incremental Auction” shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

“Flexible Resource” shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

“Forecast Pool Requirement” shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

“Foreign Guaranty” shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

“Form 715 Planning Criteria” shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

“Forward Daily Natural Gas Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

“Forward Hourly Ancillary Services Prices” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

“Forward Hourly LMPs” shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

“FTR Credit Limit” shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer

account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

“FTR Credit Requirement” shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

“FTR Flow Undiversified” shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, “FTR Historical Value” shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

“FTR Holder” shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, “FTR Monthly Credit Requirement Contribution” shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

“FTR Net Activity” shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

“FTR Participant” shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM’s FTR market.

FTR Portfolio Auction Value:

“FTR Portfolio Auction Value” shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

“Fuel Cost Policy” shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller’s method used to price fuel for calculation of the Market Seller’s cost-based offers for a generation resource.

Full Notice to Proceed:

“Full Notice to Proceed” shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

[Tariff Record Data:](#)

Record Content Description	I-J-K
Tariff Record Title	OATT Definitions - I - J - K
Record Version Number	17.0.0
Option Code	A
Record Narrative Name	OATT Definitions - I - J - K
Tariff Record ID	8
Tariff Record Collation Value	6005721
Tariff Record Parent Identifier	3
Proposed Date	2026-10-12
Priority Order	600
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

Definitions – I – J - K**IDR Transfer Agreement:**

“IDR Transfer Agreement” shall mean an agreement to transfer, subject to the terms of Tariff, Part VI, section 237, Incremental Deliverability Rights to a party for the purpose of eliminating or reducing the need for Local or Network Upgrades that would otherwise have been the responsibility of the party receiving such rights.

Immediate-need Reliability Project:

“Immediate-need Reliability Project” shall have the same meaning provided in the Operating Agreement.

Inadvertent Interchange:

“Inadvertent Interchange” shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

Incidental Expenses:

“Incidental Expenses” shall mean those expenses incidental to the performance of construction pursuant to an Interconnection Construction Service Agreement, including, but not limited to, the expense of temporary construction power, telecommunications charges, Interconnected Transmission Owner expenses associated with, but not limited to, document preparation, design review, installation, monitoring, and construction-related operations and maintenance for the Customer Facility and for the Interconnection Facilities.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction) shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed

circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Incremental Auction Revenue Rights:

“Incremental Auction Revenue Rights” shall mean the additional Auction Revenue Rights, not previously feasible, created by the addition of Incremental Rights-Eligible Required Transmission Enhancements, Merchant Transmission Facilities, or of one or more Customer-Funded Upgrades.

Incremental Available Transfer Capability Revenue Rights:

“Incremental Available Transfer Capability Revenue Rights” shall mean the rights to revenues that are derived from incremental Available Transfer Capability created by the addition of Merchant Transmission Facilities or of one of more Customer-Funded Upgrades.

Incremental Capacity Transfer Right:

“Incremental Capacity Transfer Right” shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Tariff, Schedule 12A.

Incremental Deliverability Rights (IDRs):

“Incremental Deliverability Rights” or “IDRs” shall mean the rights to the incremental ability, resulting from the addition of Merchant Transmission Facilities, to inject energy and capacity at a point on the Transmission System, such that the injection satisfies the deliverability requirements of a Capacity Resource. Incremental Deliverability Rights may be obtained by a generator or a Generation Interconnection Customer, pursuant to an IDR Transfer Agreement, to satisfy, in part, the deliverability requirements necessary to obtain Capacity Interconnection Rights.

Incremental Energy Offer:

“Incremental Energy Offer” shall mean the cost in dollars per MWh of providing an additional MWh from a synchronized unit. It consists primarily of the cost of fuel, as determined by the unit’s incremental heat rate (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances, tax credits, and energy market opportunity costs.

Incremental Multi-Driver Project:

“Incremental Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Incremental Rights-Eligible Required Transmission Enhancements:

“Incremental Rights-Eligible Required Transmission Enhancements” shall mean Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Tariff, Schedule 12) and meet one of the following criteria: (1) cost responsibility is assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

Increment Offer:

“Increment Offer” shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market.

Independent Auditor:

“Independent Auditor” shall mean an external accountant or external accounting firm who is not an employee of, not otherwise related to, not obligated to, has no interest in, and is independent in the performance of professional services for, the entity he/she/it is auditing, its management and/or its owners.

Initial Operation:

“Initial Operation” shall mean the commencement of operation of the Customer Facility and Customer Interconnection Facilities after satisfaction of the conditions of Tariff, Attachment O-Appendix 2, section 1.4 (an Interconnection Service Agreement).

Integer Relaxation:

“Integer Relaxation” shall mean the process by which the commitment status variable for an Eligible Fast-Start Resource is allowed to vary between zero and one, inclusive of zero and one, as further described in Tariff, Attachment K-Appendix, section 2.2.

Interconnected Entity:

“Interconnected Entity” shall mean either the Interconnection Customer or the Interconnected Transmission Owner; Interconnected Entities shall mean both of them.

Interconnected Transmission Owner:

“Interconnected Transmission Owner” shall mean the Transmission Owner to whose transmission facilities or distribution facilities Customer Interconnection Facilities are, or as the case may be, a Customer Facility is, being directly connected. When used in an Interconnection

Construction Service Agreement, the term may refer to a Transmission Owner whose facilities must be upgraded pursuant to the Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

Interconnection Construction Service Agreement:

“Interconnection Construction Service Agreement” shall mean the agreement entered into by an Interconnection Customer, Interconnected Transmission Owner and the Transmission Provider pursuant to Tariff, Part VI, Subpart B and in the form set forth in Tariff, Attachment P, relating to construction of Attachment Facilities, Network Upgrades, and/or Local Upgrades and coordination of the construction and interconnection of an associated Customer Facility. A separate Interconnection Construction Service Agreement will be executed with each Transmission Owner that is responsible for construction of any Attachment Facilities, Network Upgrades, or Local Upgrades associated with interconnection of a Customer Facility.

Interconnection Customer:

“Interconnection Customer” shall mean a Generation Interconnection Customer and/or a Transmission Interconnection Customer.

Interconnection Facilities:

“Interconnection Facilities” shall mean the Transmission Owner Interconnection Facilities and the Customer Interconnection Facilities.

Interconnection Feasibility Study:

“Interconnection Feasibility Study” shall mean either a Generation Interconnection Feasibility Study or Transmission Interconnection Feasibility Study.

Interconnection Party:

“Interconnection Party” shall mean a Transmission Provider, Interconnection Customer, or the Interconnected Transmission Owner. Interconnection Parties shall mean all of them.

Interconnection Request:

“Interconnection Request” shall mean a Generation Interconnection Request, a Transmission Interconnection Request and/or an IDR Transfer Agreement.

Interconnection Service:

“Interconnection Service” shall mean the physical and electrical interconnection of the Customer Facility with the Transmission System pursuant to the terms of Tariff, Part IV and Tariff, Part VI and the Interconnection Service Agreement entered into pursuant thereto by Interconnection Customer, the Interconnected Transmission Owner and Transmission Provider.

Interconnection Service Agreement:

“Interconnection Service Agreement” shall mean an agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Tariff, Part IV and Tariff, Part VI.

Interconnection Studies:

“Interconnection Studies” shall mean the Interconnection Feasibility Study, the System Impact Study, and the Facilities Study described in Tariff, Part IV and Tariff, Part VI.

Interface Pricing Point:

“Interface Pricing Point” shall have the meaning specified in Operating Agreement, Schedule 1, section 2.6A, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.6A.

Interim Resource Adequacy Service:

“Interim Resource Adequacy Service” shall mean a load reduction service through which New Large Loads reduce load as directed by the applicable Electric Distributor in response to an Interim Resource Adequacy Service Action requested by the Office of the Interconnection. Such reductions in load may be eligible for compensation pursuant to Attachment DD-4, section X.

Interim Resource Adequacy Service Action:

“Interim Resource Adequacy Service Action” shall mean an Operating Instruction, as defined by NERC, issued from the Office of the Interconnection to reduce load prior to calling on Pre-Emergency Load Management Reductions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages.

Intermittent Resource:

“Intermittent Resource” shall mean a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power and other renewable resources.

Internal Credit Score:

“Internal Credit Score” shall mean a composite numerical score determined by PJMSettlement using quantitative and qualitative metrics to estimate various predictors of a credit event happening to a Market Participant that may trigger a credit event.

Internal Market Buyer:

“Internal Market Buyer” shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

Interregional Transmission Project:

“Interregional Transmission Project” shall mean transmission facilities that would be located within two or more neighboring transmission planning regions and are determined by each of those regions to be a more efficient or cost effective solution to regional transmission needs.

Interruption:

“Interruption” shall mean a reduction in non-firm transmission service due to economic reasons pursuant to Tariff, Part II, section 14.7.

IROL Critical Resource:

“IROL Critical Resource” shall mean a generation resource that the Office of the Interconnection designates, pursuant to NERC Reliability Standards, as having an interconnection reliability operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.

Jointly Owned Cross-Subsidized Capacity Resource:

“Jointly Owned Cross-Subsidized Capacity Resource” shall mean a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

[Tariff Record Data:](#)

Record Content Description	L-M-N
Tariff Record Title	OATT Definitions - L - M - N
Record Version Number	54.0.0
Option Code	A
Record Narrative Name	Definitions - L - M - N
Tariff Record ID	9
Tariff Record Collation Value	6720824
Tariff Record Parent Identifier	3
Proposed Date	2026-10-12
Priority Order	1690
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

Definitions – L – M – N**Large Load:**

“Large Load” shall have the meaning provided in the Reliability Assurance Agreement.

Legacy Policy:

“Legacy Policy” shall mean any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Limited Demand Resource:

“Limited Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:

“Limited Demand Resource Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model

employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

“Limited Resource Constraint” shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:

“Limited Resource Price Decrement” shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:

“List of Approved Contractors” shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner’s system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Interest:

“Load Interest” shall mean, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

Load Management:

“Load Management” shall mean a Demand Resource (“DR”) as defined in the Reliability Assurance Agreement.

Load Management Event:

“Load Management Event” shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:

“Load Ratio Share” shall mean the ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load.

Load Reduction Event:

“Load Reduction Event” shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Charging Energy:

“Load Serving Charging Energy” shall mean energy that is purchased from the PJM Interchange Energy Market and stored in an Energy Storage Resource or Open-Loop Hybrid Resource for later resale to end-use load.

Load Serving Entity (LSE):

“Load Serving Entity” or “LSE” shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:

“Load Shedding” shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:

“Local Upgrades” shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:

“LOC Deviation,” shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource’s bus and adjusted for any reduction in megawatts due to Regulation, Synchronized Reserve, or Secondary Reserve assignments and limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit’s output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated real-time Locational Marginal Price at the resource’s bus, and shall be limited to the lesser of the unit’s Economic Maximum or the unit’s Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):

“Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area’s reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:

“Locational Deliverability Area Reliability Requirement” shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with

preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:

“Locational Price Adder” shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:

“Locational Reliability Charge” shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:

“Locational UCAP” shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:

“Locational UCAP Seller” shall mean a Member that sells Locational UCAP.

Long-lead Project:

“Long-lead Project” shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:

“Long-Term Firm Point-To-Point Transmission Service” shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:

“Loss Price” shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:

“M2M Flowgate” shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

“Maintenance Adder” shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller’s Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:

“Manual Load Dump Action” shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region’s load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:

“Manual Load Dump Warning” shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Marginal Value:

“Marginal Value” shall mean the incremental change in system dispatch costs, measured as a \$/MW value incurred by providing one additional MW of relief to the transmission constraint.

Market Monitor:

“Market Monitor” means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:

“Market Monitoring Unit” or “MMU” means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:

“Market Monitoring Unit Advisory Committee” or “MMU Advisory Committee” shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:

“Market Operations Center” shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:

“Market Participant” shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

“Market Participant Energy Injection” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, real-time generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:

“Market Participant Energy Withdrawal” shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Revenue Neutrality Offset:

“Market Revenue Neutrality Offset” shall mean the revenue in excess of the cost for a resource from the energy, Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve markets realized from an increase in real-time market megawatt assignment from a day-ahead market megawatt assignment in any of these markets due to the decrease in the real-time reserve market megawatt assignment from a day-ahead reserve market megawatt assignment in any of the reserve markets.

Market Seller Offer Cap:

“Market Seller Offer Cap” shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD, section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:

“Market Violation” shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:

“Material Modification” shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Maximum Daily Starts:

“Maximum Daily Starts” shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:

“Maximum Emergency” shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:

“Maximum Facility Output” shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer’s Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:

“Maximum Generation Emergency” shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:

“Maximum Generation Emergency Alert” shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:

“Maximum Run Time” shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM’s State Estimator.

Maximum State of Charge:

“Maximum State of Charge” shall mean the maximum State of Charge that should not be exceeded, measured in units of megawatt-hours.

Maximum Weekly Starts:

“Maximum Weekly Starts” shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

“Merchant A.C. Transmission Facility” shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:

“Merchant D.C. Transmission Facilities” shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:

“Merchant Network Upgrades” shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer’s Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:

“Merchant Transmission Facilities” shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:

“Merchant Transmission Provider” shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:

“Metering Equipment” shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:

“Minimum Annual Resource Requirement” shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:

For all generating units that are not combined cycle units, “Minimum Down Time” shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit’s generator breaker

opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:

"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:

For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

Minimum State of Charge:

“Minimum State of Charge” shall mean the minimum State of Charge that should be maintained in units of megawatt-hours.

MISO:

“MISO” shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Mixed Technology Facility:

“Mixed Technology Facility” shall mean a facility composed of distinct generation and/or electric storage technology types behind the same Point of Interconnection. Co-Located Resources and Hybrid Resources form all or part of Mixed Technology Facilities.

MOPR Floor Offer Price:

“MOPR Floor Offer Price” shall mean a minimum offer price applicable to certain Market Seller’s Capacity Resources under certain conditions, as determined in accordance with Tariff, Attachment DD, sections 5.14(h), 5.14(h-1), and 5.14(h-2).

Multi-Driver Project:

“Multi-Driver Project” shall have the same meaning provided in the Operating Agreement.

Native Load Customers:

“Native Load Customers” shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner’s system to meet the reliable electric needs of such customers.

Near-Term Transmission Service:

“Near-Term Transmission Service” shall mean Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. “Near-Term Transmission Service” includes any Point-To-Point Transmission Service and Network Integration Transmission Service where the start and end date of the designation or request is within the next 10 days.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:

“NERC Interchange Distribution Calculator” shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:

“Net Benefits Test” shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:

“Net Cost of New Entry” shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:

“Net Obligation” shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

“Net Sell Position” shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:

“Network Customer” shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider’s Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:

“Network Integration Transmission Service” shall mean the transmission service provided under Tariff, Part III.

Network Load:

“Network Load” shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer’s Network Load shall include all load (including losses, Non-Dispatched Charging Energy, and Load Serving Charging Energy) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load. Network Load shall not include Dispatched Charging Energy.

Network Operating Agreement:

“Network Operating Agreement” shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:

“Network Operating Committee” shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:

“Network Resource” shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:

“Network Service User” shall mean an entity using Network Transmission Service.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:

“Network Upgrades” shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider’s overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that are not part of an Affected System; only serve the Customer Interconnection Facility; and have no impact or potential impact on the Transmission System until the final tie-in is complete. Both Transmission Provider and Interconnection Customer must agree as to what constitutes Direct Connection Network Upgrades and identify them in the Interconnection Construction Service Agreement, Schedule D. If the Transmission Provider and Interconnection Customer disagree about whether a particular Network Upgrade is a Direct Connection Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Direct Connection Network Upgrade within 15 days of its determination.

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:

“Neutral Party” shall have the meaning provided in Tariff, Part I, section 9.3(v).

New Entry Capacity Resource with State Subsidy:

“New Entry Capacity Resource with State Subsidy” shall mean (1) starting with the 2022/2023 Delivery Year, the MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that have not cleared in an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price or (2) starting with the Base Residual Auction for the 2022/2023 Delivery Year, any of those MWs (in installed capacity) comprising a Capacity Resource with State Subsidy that was not included in an FRR Capacity Plan at the time of the Base Residual Auction or the subject of a Sell Offer in a Base Residual Auction occurring for a Delivery Year after it last cleared an RPM Auction and since then has yet to clear an RPM Auction pursuant to its Sell Offer at or above its resource-specific MOPR Floor Offer Price or the applicable default New Entry MOPR Floor Offer Price. Notwithstanding the foregoing, any Capacity Resource that previously cleared an RPM Auction before it became entitled to receive a State Subsidy shall not be deemed a New Entry Capacity Resource, unless, starting with the Base Residual Auction for the 2022/2023 Delivery Year, the Capacity Resource with State Subsidy was not the subject of a

Sell Offer in a Base Residual Auction or included in an FRR Capacity Plan at the time of the Base Residual Auction for a Delivery Year after it last cleared an RPM Auction.

New Large Load:

“New Large Load” shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1, 2027, or (b) incremental load in-service after June 1, 2027, that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then New Large Load shall mean end-use customer load that is either (a) a Large Load that goes into service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met or (b) incremental load in-service after June 1 of the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met that increases the existing end-use customer load at a single electrical site that, prior to such incremental load, did not previously meet the definition of Large Load.

New PJM Zone(s):

“New PJM Zone(s)” shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:

“New Service Customers” shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:

“New Service Request” shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:

“New Services Queue” shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on March 31 and September 30 of each year shall collectively comprise a New Services Queue.

New York ISO or NYISO:

“New York ISO” or “NYISO” shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:

The “Nodal Reference Price” at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May-Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July-August 2002 as their reference period.

No-load Cost:

“No-load Cost” shall mean the hourly cost required to theoretically operate a synchronized unit at zero MW. It consists primarily of the cost of fuel, as determined by the unit’s no load heat (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, and emissions allowances.

Nominal Rated Capability:

“Nominal Rated Capability” shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer’s Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer’s Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:

“Nominated Energy Efficiency Value” shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Curtailment Charge:

“Non-Curtailment Charge” shall mean the charge applicable to Demand Resources and Price Responsive Demand as defined in Tariff, Attachment DD, section 10B(b).

Non-Dispatched Charging Energy:

“Non-Dispatched Charging Energy” shall mean all Direct Charging Energy that an Energy Storage Resource Model Participant or Open-Loop Hybrid Resource receives from the electric grid that is not otherwise Dispatched Charging Energy.

Non-Firm Point-To-Point Transmission Service:

“Non-Firm Point-To-Point Transmission Service” shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:

“Non-Firm Sale” shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:

“No-Firm Transmission Withdrawal Rights” shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-PAI Event:

“Non-PAI Event” shall mean, effective for the 2028/2029 Delivery Year and subsequent Delivery Years, any intervals when a Demand Resource is dispatched or when Price Responsive Demand is required to respond and a Performance Assessment Interval is not in effect for such intervals for the same registration.

Non-Performance Charge:

“Non-Performance Charge” shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:

“Nonincumbent Developer” shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:

“Non-Regulatory Opportunity Cost” shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit’s lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:

“Non-Retail Behind The Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:

“Non-Synchronized Reserve” shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:

“Non-Synchronized Reserve Event” shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

“Non-Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:

“Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:

“Normal Maximum Generation” shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:

“Normal Minimum Generation” shall mean the lowest output level of a generating resource under normal operating conditions.

[Tariff Record Data:](#)

Record Content Description	T-U-V
Tariff Record Title	OATT Definitions - T - U - V
Record Version Number	26.0.0
Option Code	A
Record Narrative Name	Definitions - T - U - V
Tariff Record ID	12
Tariff Record Collation Value	8866133
Tariff Record Parent Identifier	3
Proposed Date	2026-10-12
Priority Order	600
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

Definitions – T – U - V**Tangible Net Worth:**

“Tangible Net Worth” shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

“Target Allocation” shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

“Third Incremental Auction” shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

“Third-Party Sale” shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

“Tie Line” shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

“Total Lost Opportunity Cost Offer” shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

“Total Net Obligation” shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

“Total Net Sell Position” shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Total Operating Reserve Offer:

“Total Operating Reserve Offer” shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.

Trade Reference:

“Trade Reference” shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

“Transmission Congestion Charge” shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement,

Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

“Transmission Congestion Credit” shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

“Transmission Constraint Penalty Factor” shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

“Transmission Customer” shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

“Transmission Facilities” shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

“Transmission Forced Outage” shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Facility Rating:

“Transmission Facility Rating” shall mean the maximum transfer capability, or the maximum or minimum voltage, current, frequency, or real or reactive power flow, through a Transmission Facility that does not violate the applicable rating of relevant transmission equipment.

Transmission Facility Ratings are computed in accordance with a written Transmission Facility Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. Transmission Facility Ratings also encompass AARs, AAR Exceptions, and Temporary Conditional Transmission Facility Ratings.

Transmission Injection Rights:

“Transmission Injection Rights” shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

“Transmission Interconnection Customer” shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

“Transmission Interconnection Facilities Study” shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

“Transmission Interconnection Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

“Transmission Interconnection Request” shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

“Transmission Loading Relief” shall mean NERC’s procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

“Transmission Loss Charge” shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

“Transmission Owner Attachment Facilities” shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner’s side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

“Transmission Owner Interconnection Facilities” shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner’s side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

“Transmission Owner Upgrade” shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

“Transmission Planned Outage” shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The “Transmission Provider” shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

- (a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;
- (b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and
- (c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider’s Monthly Transmission System Peak:

“Transmission Provider’s Monthly Transmission System Peak” shall mean the maximum firm usage of the Transmission Provider’s Transmission System in a calendar month.

Transmission Service:

“Transmission Service” shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

“Transmission Service Request” shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

“Transmission System” shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

“Transmission Withdrawal Rights” shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

“Turn Down Ratio” shall mean the ratio of a generating unit’s economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

“Unconstrained LDA Group” shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

“Unforced Capacity” shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

“Unsecured Credit” shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

“Unsecured Credit Allowance” shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement’s evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: “Working Credit Limit.”

Updated VRR Curve:

“Updated VRR Curve” shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any changes in the Reliability Requirement, Excluded RTO New Large Load Amounts, and/or Excluded LDA New Large Load Amounts from the Base Residual Auction to the relevant Incremental Auction.

Updated VRR Curve Decrement:

“Updated VRR Curve Decrement” shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

“Updated VRR Curve Increment” shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

“Upgrade Construction Service Agreement” shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

“Upgrade Customer” shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

“Upgrade Feasibility Study” shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

“Upgrade-Related Rights” shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

“Upgrade Request” shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

“Up-to Congestion Counterflow Transaction” shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month’s average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

“Up-to Congestion Historical Month” shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an “Up-to Congestion Prevailing Flow Transaction” if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

“Up-to Congestion Reference Price” for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile

For Up-to Congestion Counterflow Transactions when bid: 20th percentile

For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

“Up-to Congestion Transaction” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

“Variable Loads” shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

“Variable Resource Requirement Curve” shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:

“Virtual Credit Exposure” shall mean the amount of potential credit exposure created by a market participant’s bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

“Virtual Transaction” shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

“Virtual Transaction Screening” shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

“Virtual Transactions Net Activity” shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

“Voltage Reduction Action” shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

“Voltage Reduction Alert” shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

“Voltage Reduction Warning” shall mean a notification from PJM to warn Members that PJM’s available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

Tariff Record Data:

Record Content Description	ATTACHMENT DD.5.4
Tariff Record Title	OATT ATTACHMENT DD.5.4 Reliability Pricing Model Auctions
Record Version Number	11.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD.5.4 Reliability Pricing Model Auctions
Tariff Record ID	1147
Tariff Record Collation Value	661040069
Tariff Record Parent Identifier	1142
Proposed Date	2026-10-12
Priority Order	510
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in Tariff, Attachment DD, section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. Notwithstanding, the Base Residual Auction for the 2026/2027 Delivery Year shall be conducted in July 2025; the Base Residual Auction for the 2027/2028 Delivery Year shall be conducted in December 2025; the Base Residual Auction for the 2028/2029 Delivery Year shall be conducted in June 2026; and the Base Residual Auction for the 2029/2030 Delivery Year shall be conducted in December 2026. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year. Notwithstanding, for the 2025/2026 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2025; for the 2026/2027 Delivery Year, only the Third Incremental Auction shall be conducted, which will commence on February 2026; for the 2027/2028 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which will commence on July 2026 and February 2027, respectively; for the 2028/2029 Delivery Year, only the Second Incremental Auction and Third Incremental Auction shall be conducted, which shall commence on July 2027 and February 2028, respectively.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements (and inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement or the LDA Reliability Requirement (inclusive of any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement;

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained; or

iii) regarding a Generation Capacity Resource that is subject to Tariff, Attachment DD, section 5.3(b), (a) the Office of Interconnection determines prior to the Third Incremental Auction that such resource will not meet the criteria set forth in Tariff, Attachment DD, section 5.3(b)(i) for the relevant Delivery Year or (b) such resource's final Accredited UCAP is less than the UCAP amount considered in the Base Residual Auction in which the resource was deemed to be the subject of a Sell Offer.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year and any adjustments associated with Excluded RTO New Large Load Amounts or Excluded LDA New Large Load Amounts) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts); provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the

PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, decrease in Accredited UCAP Factor, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

Tariff Record Data:

Record Content Description	ATTACHMENT DD.5.10
Tariff Record Title	OATT ATTACHMENT DD.5.10 Auction Clearing Requirements
Record Version Number	38.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD.5.10 Auction Clearing Requirements
Tariff Record ID	1153
Tariff Record Collation Value	665330687
Tariff Record Parent Identifier	1142
Proposed Date	2026-10-12
Priority Order	520
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement or Locational Deliverability Area Reliability Requirement for such Delivery Year. For any auction, the Updated Forecast Peak Load applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis.
- For the 2025/2026 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 98.9%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.6%]; and

- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.8%].
- For the 2026/2027 Delivery Year and 2027/2028 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to $\$256.75/\text{MW-day ICAP}$ divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];
 - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches $\$138.25/\text{MW-day ICAP}$ divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at $\$138.25/\text{MW-day ICAP}$ divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
- For the 2028/2029 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of $\$256.75/\text{MW-day ICAP}$ divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by

(the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];

- For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 106.0%].
- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
 - For the 2029/2030 Delivery Year, the Variable Resource Requirement curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to the lesser of \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource or the value of point 1, until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%];
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%.

- Once the horizontal line intersects the above curve, the Variable Resource Requirement Curve shall follow the lines that are based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource for the remainder of the curve.
 - For the 2030/2031 Delivery Year and for subsequent Delivery Years, the Variable Resource Requirement curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:
 - For point (1), price equals: {the greater of [1.15 times Cost of New Entry minus 0.75 times the Net Energy and Ancillary Service Revenue Offset] or [0.2 times Cost of New Entry]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 99%];
 - For point (2), price equals: [0.5 times the price calculated for point 1] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 101.5%; and
 - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement minus Excluded RTO New Large Load Amounts] multiplied by 106.0%].
- ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:
- A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or
 - B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or
 - C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year, the Eastern Mid-Atlantic Region

("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, beginning with the 2029/2030 Delivery Year, the points on the LDA Variable Resource Requirement Curves will be reduced by the relevant Excluded LDA New Large Load Amounts. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For Delivery Years up to and including the 2027/2028 Delivery Year for each such LDA, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA.

For the 2028/2029 Delivery Year and for subsequent Delivery Years for each such LDA, the Office of the Interconnection shall determine the applicable Cost of New Entry and Net Energy and Ancillary Services Revenue Offset value for each LDA, with such Cost of New Entry equal to the average of all five Cost of New Entry areas for RTO and the average of the Cost of New Entry for all zones in an LDA, and the Net Energy and Ancillary Services Revenue Offset value equal to the 67th percentile of the Net Energy and Ancillary Services Revenue Offset for all zones in such LDA.

- iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

- A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.
 - C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
- iv) Cost of New Entry
- A) For the Incremental Auctions, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for each corresponding Delivery Year and LDA. For the Delivery Year commencing on June 1, 2022 through and including the Delivery Year commencing on June 1, 2025, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	108,000
BGE, PEPCO (“CONE Area 2”)	109,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	105,500
PPL, MetEd, Penelec (“CONE Area 4”)	105,500

A-1) Cost of New Entry for 2025/2026 Delivery Year

A new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all CONE Areas.

B) Beginning with the 2023/2024 Delivery Year through and including the 2025/2026 Delivery Year, the CONE for each CONE Area (except for CONE Area 5) shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law, in accordance with the following:

- (1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%), as each such index

is further specified for each CONE Area in the PJM Manuals.

- (2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area, and then multiplying the result by 1.022.
 - (3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2022/2023 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years), and then multiplying the result by 1.022.
 - (4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.
- C) For the 2026/2027 Delivery Year and 2027/2028 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(C)(1).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	136,000
BGE, PEPCO (“CONE Area 2”)	142,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	147,600
PPL, MetEd, Penelec (“CONE Area 4”)	143,500

4")	
ComEd ("CONE Area 5")	150,800

- (1) For the 2027/2028 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, in accordance with the following:
 - (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Price Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 15%), as each such index is further specified for each CONE Area in the PJM Manuals.
 - (b) For CONE Areas 1 through 4, the Benchmark CONE for each CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2026/2027 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).
 - (c) For the 2027/2028 Delivery Year, the CONE for CONE Area 5 for a given Delivery Year shall be set equal to the product of the CONE of CONE Area 3 as determined for the relevant Delivery Year in accordance with (a) and (b) above, multiplied by the asset life factor applicable to that Delivery

Year where such asset life factors is 1.0376 for the 2027/2028 Delivery Year.

- (d) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.
- D) For the 2028/2029 Delivery Year and for subsequent Delivery Years, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in \$/MW-Year (ICAP)
PS, JCP&L, AE, PECO, DPL, RECO (“CONE Area 1”)	218,000
BGE, PEPCO (“CONE Area 2”)	222,000
AEP, Dayton, APS, DQL, ATSI, DEOK, EKPC, Dominion, OVEC (“CONE Area 3”)	215,000
PPL, MetEd, Penelec (“CONE Area 4”)	216,000
ComEd (“CONE Area 5”)	248,000

- (1) Beginning with the 2029/2030 Delivery Year, the Cost of New Entry for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index, in accordance with the following:
- (a) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time Cost of New Entry values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the Quarterly Census of Employment and Wages, which shall use

NAICS 2371 Utility System Construction, Private, All Establishment Sizes (weighted 15%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type, Materials and Components for Construction (weighted 10%), BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment, Turbines and Turbine Generator Sets (weighted 46%), and the Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2017=100, Seasonally Adjusted (weighted 29%), as each such index is further specified for each CONE Area in the PJM Manuals.

- (b) For CONE Areas 1 through 5, the Benchmark CONE for each CONE Area shall be the Cost of New Entry used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Cost of New Entry values stated in subsection (a)(iv)(C) above shall be the Benchmark CONE values for the 2028/2029 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the Cost of New Entry for subsequent Delivery Years).
 - (c) For the 2029/2030 Delivery Year through and including the 2031/2032 Delivery Year, the Cost of New Entry for CONE Area 5 for a given Delivery Year shall be multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.025 for the 2029/2030 Delivery Year, 1.054 for the 2030/2031 Delivery Year, and 1.088 for the 2031/2032 Delivery Year.
- v) Net Energy and Ancillary Services Revenue Offset for 2023/2024 Delivery Year through and including the 2025/2026 Delivery Years (except that the calculation of the MOPR Floor Price pursuant to Tariff, Attachment DD, section 5.14(h-2) for combustion turbine resources shall remain applicable beyond the 2025/2026 Delivery Year):
 - A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate

and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of \$6.93 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of \$2,199 per MW-year to be included through the 2025/2026 Delivery Year.

- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

v-1) Net Energy and Ancillary Services Revenue Offset for the 2026/2027 Delivery Year and subsequent Delivery Years:

- A) For the 2026/2027 and the 2027/2028 Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the average of the net energy and ancillary services revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each net energy and ancillary services revenue simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$1.19 per MWh and \$21,170 per start-up, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder

appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

- A-1) For the 2028/2029 and subsequent Delivery Years, the Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as the 67th percentile of all of the calculated zonal Net Energy and Ancillary Services Revenues Offsets that the Reference Resource is projected to receive from the PJM energy and ancillary service markets for the applicable Delivery Year from three separate simulations, with each such simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such hourly shapes. Each Net Energy and Ancillary Service Revenue Offset simulation is based on (a) the heat rate and other characteristics of such Reference Resource such as assumed variable operation and maintenance expenses of \$2.65 per MWh, and emissions costs; (b) Forward Hourly LMPs for the PJM Region; (c) Forward Hourly Ancillary Services Prices, (d) Forward Daily Natural Gas Prices at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals; and (e) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.
- B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the Forward Hourly LMPs for such Zone shall be used in place of the Forward Hourly LMP for the PJM Region; (2) if such Zone was not integrated into the PJM Region for the entire three calendar years preceding the time of the determination for the RPM Auction, then simulations shall rely on only those whole calendar years during which the Zone was integrated; and (3) Forward Daily Natural Gas Prices for the fuel pricing point mapped to such Zone.
- C) “Forward Hourly LMPs” shall be determined as follows:
- (1) Identify the liquid hub to which each Zone is mapped, as specified in the PJM Manuals.
 - (2) For each liquid hub, calculate the average day-ahead on-peak and day-ahead off-peak energy prices for each month during the Delivery Year over the most recent thirty trading

days as of 180 days prior to the Base Residual Auction. For each of the remaining steps, the historical prices used herein shall be taken from the most recent three calendar years preceding the time of the determination for the RPM Auction:

- (3) Determine and add monthly basis differentials between the hub and each of its mapped Zones to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. This differential is developed using the prices for the Planning Period closest in time to the Delivery Year from the most recent long-term Financial Transmission Rights auction conducted prior to the Base Residual Auction. The difference between the annual long-term Financial Transmission Rights auction prices for the Zone and the hub are converted to monthly values by adding, for each month of the year, the difference between (a) the historical monthly average day-ahead congestion price differentials between the Zone and relevant hub and (b) the historical annual average day-ahead congestion price differentials between the Zone and hub. This step is only used when developing forward prices for locations other than the liquid hubs;
- (4) Determine and add marginal loss differentials to the forward monthly day-ahead on-peak and off-peak energy prices for the hub. For each month of the year, calculate the marginal loss differential, which is the average of the difference between the loss components of the historical on peak or off peak day-ahead LMPs for the Zone and relevant hub in that month across the three year period scaled by the ratio of (a) the forward monthly average on-peak or off-peak day-ahead LMP at such hub to (b) the average of the historical on-peak or off-peak day-ahead LMPs for such hub in that month across the three year period. This step is only used when developing forward prices for locations other than the liquid hubs;
- (5) Shape the forward monthly day-ahead on-peak and off-peak prices to (a) forward hourly day-ahead LMPs using historic hourly day-ahead LMP shapes for the Zone and (b) forward hourly real-time LMPs using historic hourly real-time LMP shapes for the Zone. The historic hourly shapes are based on the ratio of the historic day-ahead or real-time LMP for the Zone for each given hour in a monthly on-peak or off-peak period to the average of the historic day-ahead or real-time LMP for the Zone for all hours in such

monthly on-peak or off-peak period. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction;

- (6) For unit-specific energy and ancillary service offset calculations, determine and apply basis differentials from the Zone to the generation bus to the forward day-ahead and real-time hourly LMPs for the Zone. The differential for each hour of the year is developed using the difference between the historical DA or RT LMP for the generation bus and the historical DA or RT LMP for the Zone in which the generation bus is located for that same hour; and
 - (7) Develop the Forward Hourly LMPs for the PJM Region pricing point. Calculate the load-weighted average of the monthly on-peak and off-peak Zonal LMPs developed in step (4) above, using the historical average load within each monthly on-peak or off-peak period. The load-weighted average monthly on-peak or off-peak Zonal LMPs are then shaped to forward hourly day-ahead and real-time LMPs using the same procedure as defined in step (5) above, except using historical LMPs for the PJM Region pricing point.
- D) Forward Hourly Ancillary Services Prices shall include prices for Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve and shall be determined as follows. The historical prices used herein shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction:
- (1) For Synchronized Reserve, the forward real-time Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year;
 - (2) For Non-Synchronized Reserve, the forward real-time Non-Synchronized Reserve market clearing price shall be calculated by multiplying the historical RTO real-time hourly Non-Synchronized Reserve market clearing price for each hour of the Delivery Year by the ratio of the real-

time Forward Hourly LMP at an appropriate pricing point, as defined in the PJM manuals, to the historic hourly real-time LMP at such pricing point for the corresponding hour of the year; and

- (3) For Secondary Reserve, the forward day-ahead and real-time Secondary Reserve market clearing price shall be \$0.00/MWh for all hours.

E) Forward Daily Natural Gas Prices shall be determined as follows:

- (1) Map each Zone to the appropriate natural gas hub in the PJM Region, as listed in the PJM Manuals;
- (2) Map each natural gas hub lacking sufficient liquidity to the liquid hub to which it has the highest historic price correlation;
- (3) For each sufficiently liquid natural gas hub, calculate the simple average natural gas monthly settlement prices over the most recent thirty trading days as of 180 days prior to the Base Residual Auction;
- (4) Calculate the forward monthly prices for each illiquid hub by scaling the forward monthly price of the mapped liquid hub by the average ratio of historical monthly prices at the insufficiently liquid hub to the historical monthly prices at the sufficiently liquid over the most recent three calendar years preceding the time of determination for the RPM Auction;
- (5) Shape the forward monthly prices for each hub to Forward Daily Natural Gas Prices using historic daily natural gas price shapes for the hub. The historic daily shapes are based on the ratio of the historic price for the hub for each given day in a month to the average of the historic prices for the hub for all days in such month. The daily prices are then assigned to each hour starting 10am Eastern Prevailing Time each day. The historical prices used in this step shall be taken from one of each of the most recent three calendar years preceding the time of the determination for the RPM Auction.

vi) Process for Establishing Parameters of Variable Resource Requirement

Curve

- A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.
- B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement. The Variable Resource Requirement Curve shall be posted on the same timeline with the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement. Notwithstanding, for the 2029/2030 Delivery Year, the updated VRR Curve that incorporates any Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts shall be posted one month prior to the commencement of the relevant RPM Auction.
- C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.
 - 1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 2) The PJM Members shall review the proposed values.
 - 3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.
 - 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base

Residual Auction for the first Delivery Year in which the new values would be applied.

- D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.
- 1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 2) The PJM Members shall review the proposed methodology.
 - 3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.
 - 4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the Reliability Assurance Agreement.

c) [Reserved]

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Tariff Record Data:

Record Content Description	ATTACHMENT DD.5.11
Tariff Record Title	OATT ATTACHMENT DD.5.11 Posting of Information Relevant to t
Record Version Number	21.0.0
Option Code	A
Record Narrative Name	OATT ATT DD.5.11 Posting of Information Relevant to the RPM Auctions
Tariff Record ID	1154
Tariff Record Collation Value	665688238
Tariff Record Parent Identifier	1142
Proposed Date	2026-10-12
Priority Order	510
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, (through the 2024/2025 Delivery Year), the pool-wide average Accredited UCAP Factor (beginning with the 2025/2026 Delivery Year), the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) Beginning with the 2029/2030 Delivery Year, the quantity of Excluded RTO New Large Load Amounts and Excluded LDA New Large Load Amounts used in establishing the Variable Resource Requirement Curve;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in Tariff, Attachment DD, section 5.11A;

vii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

viii) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

c) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

d) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

e) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results for each Base Residual Auction shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price.

If PJM discovers a potential error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, along with a description detailing the cause and scope of the error, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. The provided description will not contain information that is market sensitive or confidential. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

Tariff Record Data:

Record Content Description	ATTACHMENT DD.5.12
Tariff Record Title	OATT ATTACHMENT DD.5.12 Conduct of RPM Auctions
Record Version Number	27.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD.5.12 Conduct of RPM Auctions
Tariff Record ID	1156
Tariff Record Collation Value	667475996
Tariff Record Parent Identifier	1142
Proposed Date	2026-10-12
Priority Order	520
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that

corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement;
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;
- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and
- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts), utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement (inclusive of any updated adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts) and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement (inclusive of any updated

adjustments to the Excluded RTO New Large Load Amounts and/or Excluded LDA New Large Load Amounts), utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(v) (reserved)

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits (“Excess Commitment Credits”) under certain circumstances as follows:

- (A) [Reserved]
- (B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;
- (C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;
- (D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4
Tariff Record Title	OATT ATTACHMENT DD-4 INTERIM RESOURCE ADEQUACY SERVICE
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4 INTERIM RESOURCE ADEQUACY SERVICE
Tariff Record ID	2346
Tariff Record Collation Value	680461120
Tariff Record Parent Identifier	1132
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

ATTACHMENT DD-4

INTERIM RESOURCE ADEQUACY SERVICE

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.I
Tariff Record Title	OATT ATTACHMENT DD-4.I INTRODUCTION
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.I INTRODUCTION
Tariff Record ID	2347
Tariff Record Collation Value	680461130
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

I. INTRODUCTION

This Attachment DD-4 sets forth the terms and conditions governing the provision of Interim Resource Adequacy Service. As more fully set forth in this Attachment and the PJM Manuals, and in conjunction with the Reliability Assurance Agreement:

(a) Interim Resource Adequacy Service is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that are not in arrangements with new capacity additions to the PJM Region;

(b) Starting with the 2027/2028 Delivery Year, the Office of the Interconnection may, in accordance with the Manuals, instruct the implementation of an Interim Resource Adequacy Service Action prior to calling on Pre-Emergency Load Management Reductions Actions after determining that available economic real-time supply may not be sufficient to maintain reserves to meet applicable Reserve Requirements and/or Interconnection Reliability Operating Limits within prescribed limits and prevent cascading outages;

(c) The Large Load Registry maintained by the Office of the Interconnection, pursuant to the Reliability Assurance Agreement, shall inform which New Large Loads are eligible to be called on to provide Interim Resource Adequacy Service; and

(d) The Office of the Interconnection shall coordinate with Electric Distributors, and other Members as appropriate, on the provision of Interim Resource Adequacy Service and the compensation for providing Interim Resource Adequacy Service.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.II
Tariff Record Title	OATT ATTACHMENT DD-4.II RESPONSIBILITIES
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.II RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION
Tariff Record ID	2348
Tariff Record Collation Value	680461140
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

II. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

The Office of the Interconnection shall:

- (a) maintain the Large Load Registry, pursuant to Reliability Assurance Agreement, Schedule 11;
- (b) identify Eligible New Large Loads;
- (c) determine the megawatt quantity of New Large Loads eligible to provide Interim Resource Adequacy Service in each Electric Distributor zone/area for a given Delivery Year;
- (d) starting with the 2027/2028 Delivery Year, issue an Interim Resource Adequacy Service Action based on system conditions; and
- (e) request Electric Distributors to direct that a quantity of Eligible New Large Load Amounts in their respective zone(s)/area(s) be reduced in accordance with an Interim Resource Adequacy Service Action.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.III
Tariff Record Title	OATT ATTACHMENT DD-4.III RESPONSIBILITIES OF ELECTRIC DISTRIB
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.III RESPONSIBILITIES OF ELECTRIC DISTRIBUTORS
Tariff Record ID	2349
Tariff Record Collation Value	680461150
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

III. RESPONSIBILITIES OF ELECTRIC DISTRIBUTORS

Electric Distributors shall:

- (a) execute the Office of the Interconnection's directives to implement Interim Resource Adequacy Service Actions among the Eligible New Large Loads in the Electric Distributor's zone/area, which is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value and is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering;
- (b) coordinate with the Office of the Interconnection in developing and maintaining the Large Load Registry by providing the Office of the Interconnection any information or data the Electric Distributor believes appropriate to facilitate an accurate Large Load Registry, including applicable state or RERRA retail tariff or contractual obligations;
- (c) coordinate, as appropriate, with the relevant state(s) or RERRA(s), individual Load Serving Entities, and customers served by the Load Serving Entities in its zone/area to support transparent, effective, and orderly deployment of Interim Resource Adequacy Service; and
- (d) implement compensation program consistent with Tariff, Attachment DD-4, section X.

[Tariff Record Data:](#)

Record Content Description	ATTACHMENT DD-4.IV
Tariff Record Title	OATT ATTACHMENT DD-4.IV DETERMINATION OF MAXIMUM INTERIM RES
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.IV DETERMINATION OF MAXIMUM INTERIM RESOURCE ADEQUACY SERVICE EACH ELIGIBLE NEW LARGE LOAD MAY PROVIDE IN A DELIVERY YEAR
Tariff Record ID	2350
Tariff Record Collation Value	680461160
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

IV. DETERMINATION OF MAXIMUM INTERIM RESOURCE ADEQUACY SERVICE EACH ELIGIBLE NEW LARGE LOAD MAY PROVIDE IN A DELIVERY YEAR

- (a) All Eligible New Large Loads shall be available to be requested to provide Interim Resource Adequacy Service by the Office of the Interconnection.
- (b) The amount of Interim Resource Adequacy Service available to the Office of the Interconnection may change for each Delivery Year depending on the relationship of the amount of Capacity Resources committed, through Tariff, Attachment DD, for a given Delivery Year, and the Eligible New Large Load Amounts.
 - (i) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount greater than the sum (in MW) of all Eligible New Large Load Amounts, then all Eligible New Large Load Amounts is needed by the Office of the Interconnection to be available to provide Interim Resource Adequacy Service for that Delivery Year;
 - (ii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) is less than the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor) by an amount less than the sum (in MW) of all Eligible New Large Load Amounts, then the difference (in MW) shall be the cumulative amount (in MW) of Eligible New Large Load Amounts that the Office of the Interconnection needs to be available to provide Interim Resource Adequacy Service for that Delivery Year; and
 - (iii) In the event ([the amount of Capacity Resources committed for a given Delivery Year (as determined after the Third Incremental Auction) equals or exceeds the PJM Region Reliability Requirement determined prior to the Third Incremental Auction] divided by the Pool-wide Accredited UCAP Factor), then the Office of the Interconnection does not need any Eligible New Large Loads to be available to provide Interim Resource Adequacy Service for that Delivery Year.
- (c) For each Delivery Year that meets the requirements of Tariff, Attachment DD-4, sections IV(b)(i) or IV(b)(ii), the Office of the Interconnection shall determine:
 - (i) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis across the PJM Region for the Delivery Year; and
 - (ii) the total amount of Interim Resource Adequacy Service (in MW) needed to be available on a daily basis in each Electric Distributor zone/area for the Delivery Year, which shall be equal to

the product of the sum of all Eligible New Large Load Amounts needed in the PJM Region pursuant to Attachment DD-4, section IV(b) multiplied by the quotient of [(the sum of all Eligible New Large Load Amounts in the Electric Distributor's zone/area) divided by (the sum of all Eligible New Large Load Amounts in the PJM Region)].

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.V
Tariff Record Title	OATT ATTACHMENT DD-4.V DETERMINATION OF NEW LARGE LOADS ELIG
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.V DETERMINATION OF NEW LARGE LOADS ELIGIBILITY TO PROVIDE INTERIM RESOURCE ADEQUACY SERVICE
Tariff Record ID	2351
Tariff Record Collation Value	680461170
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

V. DETERMINATION OF NEW LARGE LOADS ELIGIBILITY TO PROVIDE INTERIM RESOURCE ADEQUACY SERVICE

(a) All New Large Loads shall be Eligible New Large Loads to the extent that the sum of a New Large Load's Eligible New Large Load Amount is less than the New Large Load's registered peak load (in MW), as provided in the Large Load Registry. New Large Loads with a cumulative installed capacity equivalent of their BYONC arrangements and assigned Allocated RBP UCAP MW that equals or exceeds the New Large Load's registered peak load, as provided in the Large Load Registry, shall not be Eligible New Large Loads. New Large Loads that are located within an FRR Service Area cannot be Eligible New Large Loads.

(b) A New Large Load's Eligible New Large Load Amount shall be determined as follows:

(New Large Load's registered peak load (in MW), as provided in the Large Load Registry) minus (the sum of all BYONC arrangements with the New Large Load in accordance with Tariff, Attachment DD-4, section VII divided by the Forecast Pool Requirement for the first Delivery Year in which the BYONC cleared an RPM Auction, plus Allocated RBP UCAP MW assigned to the New Large Load, in accordance with Tariff, Attachment DD-4, section IX divided by the Forecast Pool Requirement for the first Delivery Year in which the Allocated RBP UCAP MW cleared an RPM Auction).

(c) For purposes of removing its eligibility to provide Interim Resource Adequacy Service, a New Large Load may enter into arrangements with BYONC supported by one or more resources.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.VI
Tariff Record Title	OATT ATTACHMENT DD-4.VI BRING YOUR OWN NEW CAPACITY CRIT
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.VI BRING YOUR OWN NEW CAPACITY CRITERIA
Tariff Record ID	2352
Tariff Record Collation Value	680461180
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

VI. BRING YOUR OWN NEW CAPACITY CRITERIA

- (a)
 - (i) Capacity Resources that cleared an RPM Auction for the first time in the Base Residual Auction for the 2027/2028, 2028/2029, and 2029/2030 Delivery Years may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below.
 - (ii) Megawatts of Unforced Capacity that have not cleared an RPM Auction, other than those specified in subsection (a)(i) above, may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below. To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then megawatts of Unforced Capacity may qualify as BYONC to the extent the underlying resource meets the criteria in subsection (b) below and such megawatts (1) have not cleared in an RPM Auction conducted for a Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met and (2) meet the eligibility criteria set forth in Tariff, Attachment DD-4, section VI.
 - (iii) With the exception of the RPM Auctions listed in subsection (a)(i) above, to the extent megawatts of Unforced Capacity that have cleared an RPM Auction before any arrangement with a New Large Load based on such megawatts was reported to the Office of the Interconnection, then such megawatts of Unforced Capacity cannot qualify as BYONC even if the underlying resource meets the criteria in subsection (b) below.
- (b) To qualify as Bring Your Own New Capacity, resources must meet the following eligibility requirements:
 - (i) For generation and storage resources, the resource must be supported by one of the following:
 - (1) a new-build generation resource including new resources that obtain Capacity Interconnection Rights transferred from deactivated resources or resources that have announced deactivation as of April 10, 2026;
 - (2) the incremental capacity created by an uprate of Existing Generation Capacity Resources, but only to the extent such incremental capacity is created through an increase in such Generation Capacity Resource's installed capacity and increase in Capacity Interconnection Rights associated with that Generation Capacity Resource;
 - (3) the incremental capacity created by the utilization of Surplus Interconnection Service;
 - (4) repowering of a deactivated generation resource that deactivated prior to April 10, 2026; or

- (5) incremental capacity, whether due to greater Unforced Capacity or a higher level of Capacity Interconnection Rights, created by an Existing Generation Capacity Resource's changing fuel type to a more efficient fuel type.
- (ii) For Demand Resources or DER Capacity Aggregation Resources, the resource must qualify as a Planned Demand Resource or DER Capacity Aggregation Resource, as described in the RAA, Schedule 6 and Schedule 6.2 and:
 - (1) be composed of, or reliant on, any location not registered in or prior to the 2026/2027 Delivery Year at which an incremental amount at that location is the result of the registration of new generation or storage assets at the location. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, any location registered in the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met; and/or
 - (2) be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for or prior to the 2026/2027 Delivery Year. However, to the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then will be composed of, or reliant on, locations that were not previously supported a Capacity Resource, a Peak Shaving Adjustment, or Price Responsive Demand for the Delivery Year prior to the first Delivery Year for which the requirements of Tariff, Attachment DD-4, section IV(b)(iii) are not met.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.VII
Tariff Record Title	OATT ATTACHMENT DD-4.VII BRING YOUR OWN NEW CAPACITY ARRANGE
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.VII BRING YOUR OWN NEW CAPACITY ARRANGEMENTS WITH NEW LARGE LOADS
Tariff Record ID	2353
Tariff Record Collation Value	680461190
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

VII. BRING YOUR OWN NEW CAPACITY ARRANGEMENTS WITH NEW LARGE LOADS

- (a) For any BYONC to be in an arrangement with a New Large Load,
 - (i) the Load Serving Entity serving the New Large Load or the applicable Electric Distributor shall report the BYONC in an arrangement with the New Large Load, in accordance with the PJM Manuals. The Office of the Interconnection may also accept information to the extent interconnection customers, Large Loads, Transmission Owners, or other entities voluntarily report any BYONC that may be in an arrangement with a New Large Load; and
 - (ii) the resource owner or entity with contractual authority to enter into a BYONC arrangement must certify to the Office of Interconnection, in accordance with the PJM Manuals, attesting to the arrangement with the New Large Load and that the BYONC will follow the requirements of Tariff, Attachment DD-4, section VIII.
- (b) For an arrangement between a New Large Load and BYONC to be effective for the 2027/2028 and 2028/2029 Delivery Years, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be met by April 1 for the first Delivery Year such arrangement is to result in a reduction in the New Large Load's Eligible New Large Load Amount. By April 15, the Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC.
- (c) For an arrangement between a New Large Load and BYONC to be effective for the 2029/2030 Delivery Year, for any BYONC arrangement to be considered, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 50 days prior to the commencement of the 2029/2030 Base Residual Auction or by 30 days prior to the posting of the planning parameters for the Incremental Auctions arrangement for the 2029/2030 Delivery Year. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (d) For an arrangement between a New Large Load and BYONC to be effective for the 2030/2031 Delivery Year and subsequent Delivery Years, the requirements of Tariff, Attachment DD-4, section VII(a) must be reported to the Office of the Interconnection no later than by 30 days prior to the posting of the planning parameters for the relevant RPM Auction for the initial Delivery Year the BYONC enters into an arrangement with the New Large Load. The Office of the Interconnection shall update the Large Load Registry to reflect any verified arrangements between New Large Loads and BYONC after the relevant RPM Auction.
- (e) BYONC that is in an arrangement with a New Large Load must remain in such arrangement with that New Large Load unless and until the New Large Load is permanently out-of-service.
- (f) A physical resource may support multiple BYONC, each of which may be in an

arrangement with different New Large Loads, as long as no BYONC is in an arrangement with more than one New Large Load.

(g) A New Large Load may enter into an arrangement with discrete BYONC supported by different physical resources.

(h) A New Large Load may enter into an arrangement with BYONC in excess of its current Eligible Large Load Amount, e.g., to allow for expected growth in the New Large Load, and the full megawatt quantity of such BYONC shall be offered in the first RPM Auction for which the New Large Load is included in the Variable Resource Requirement Curve.

(i) (i) For any generation or storage resource, the Accredited UCAP of any BYONC shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load.

(ii) For Demand Resources or DER Capacity Aggregation Resources, the Accredited UCAP shall be the Accredited UCAP for the RPM Auction in which the BYONC cleared for the initial Delivery Year the BYONC is in an arrangement with the New Large Load and must be demonstrated each year for a 10-year period using the Demand Response or DER Capacity Aggregation Resources installed capacity for the first Delivery Year after the BYONC is in an arrangement with the New Large Load. For Demand Resources or DER Capacity Aggregation Resources that are also the actual New Large Load, there is no demonstration required for the initial Delivery Year only to not be an Eligible New Large Load.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.VIII
Tariff Record Title	OATT ATTACHMENT DD-4.VIII BRING YOUR OWN NEW CAPACITY PARTIC
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.VIII BRING YOUR OWN NEW CAPACITY PARTICIPATION IN THE RELIABILITY PRICING MODEL
Tariff Record ID	2354
Tariff Record Collation Value	680461200
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

VIII. BRING YOUR OWN NEW CAPACITY PARTICIPATION IN THE RELIABILITY PRICING MODEL

- (a) All BYONC in an arrangement with a New Large Load must meet the requirements in Tariff, Attachment DD, section 5.5A and become Capacity Resources eligible to participate in RPM Auctions.
- (b) All BYONC in an arrangement with a New Large Load must be offered into the RPM Auctions as Capacity Resources consistent with and pursuant to the capacity must-offer requirements and exceptions set forth in Tariff, Attachment DD, sections 6.6 and 6.6A. BYONC may not seek an exception to the capacity must-offer requirement to provide an external sale, as available under Tariff, Attachment DD, section 6.6(g) for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load.
- (c) All BYONC in an arrangement with a New Large Load and committed through RPM Auctions will be subject to all capacity market rules, as set forth in Tariff, Attachments DD and DD-1.
- (d) To the extent the resource supporting a BYONC arrangement is unavailable in a given Delivery Year, the seller of such resource will be subject to all relevant deficiency charges under Tariff, Attachment DD.
- (e) All BYONC in an arrangement with a New Large Load and not qualifying for an exception pursuant to Tariff, Attachment DD, section 6.6(g), must be offered into the applicable RPM Auctions as price takers, i.e., \$0/MW-day UCAP for a 10-year period starting with the first Delivery Year which the BYONC is in an arrangement with the New Large Load. To the extent the resource is a Demand Resource or DER Capacity Aggregation Resource, the BYONC shall participate in RPM Auctions for ten (10) consecutive Delivery Years as an Annual Demand Resource or DER Capacity Aggregation Resource, as applicable; provided, however, the seller of such Demand Resource or DER Capacity Aggregation Resource may, in accordance with Tariff, Attachment DD-4, section VII(a)(i) report to the Office of the Interconnection BYONC that replaces such BYONC, where such replacement shall be for the remainder of the replaced BYONC's ten-year RPM Auction participation commitment and the replaced BYONC (and its supporting registrations) may no longer provide BYONC. In such event, the replacement BYONC would need to be supported by the certification required by Tariff, Attachment DD-4, section VII(a)(ii), and such replacement arrangement must be effective coincident with the initial BYONC releasing its arrangement.
- (f) To the extent three consecutive Delivery Years meet the requirements of Tariff, Attachment DD-4, section IV(b)(iii), then any existing BYONC are relieved of the obligations under this Tariff, Attachment DD-4, section VIII.

Tariff Record Data:

Record Content Description	ATTACHMENT DD-4.IX
Tariff Record Title	OATT ATTACHMENT DD-4.IX ALLOCATION OF RBP UCAP MW
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.IX ALLOCATION OF RBP UCAP MW
Tariff Record ID	2355
Tariff Record Collation Value	680461210
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

IX. ALLOCATION OF RBP UCAP MW

- (a) Each Electric Distributor zone/area allocated RBP Charges pursuant to Tariff, Attachment DD, section 18.3(a) shall be allocated RBP UCAP MW on a pro-rata basis using the Electric Distributor zone/area's assigned share of the total Final RBP Target MW across all zone/areas.
- (b) Each New Large Load's Allocated RBP UCAP MW shall be determined as follows:
 - (i) Each Electric Distributor allocated RBP UCAP MW shall inform the Office of the Interconnection how such RBP UCAP MW should be further allocated among the New Large Loads located in the Electric Distributor's zone/area; or
 - (ii) In the event the Electric Distributor has not informed the Office of the Interconnection how its RBP UCAP MW should be further allocated by April 1 before a given Delivery Year, the Office of the Interconnection shall allocate such RBP UCAP MW to the Electric Distributor's zone/area pro-rata among all New Large Loads located in the zone/area.
- (c) The Office of the Interconnection shall list in the Large Load Registry each New Large Load's Allocated RBP UCAP MW.

[Tariff Record Data:](#)

Record Content Description	ATTACHMENT DD-4.X
Tariff Record Title	OATT ATTACHMENT DD-4.X COMPENSATION FOR PROVIDING INTERIM RE
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	OATT ATTACHMENT DD-4.X COMPENSATION FOR PROVIDING INTERIM RESOURCE ADEQUACY SERVICE
Tariff Record ID	2356
Tariff Record Collation Value	680461220
Tariff Record Parent Identifier	2346
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

X. COMPENSATION FOR PROVIDING INTERIM RESOURCE ADEQUACY SERVICE

- (a) The rate for the provision of Interim Resource Adequacy Service shall be 50% of the Non-Performance Charge Rate specified in Tariff, Attachment DD, section 10A(e), unless any Eligible New Large Load elects to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service as contemplated by Tariff, Attachment DD-4, section X(c). If any Eligible New Large Load so elects to accept less than 50% of the Non-Performance Charge Rate or waives in its entirety receipt of compensation for the provision of wholesale Interim Resource Adequacy Service, the wholesale rate for the provision of Interim Resource Adequacy Service shall reflect the accepted sum less than 50% of the Non-Performance Charge Rate or if compensation is waived entirely, the rate shall be zero dollars.
- (b) (i) Following an Interim Resource Adequacy Event, unless the Electric Distributor informs the Office of the Interconnection otherwise in accordance with Tariff, Attachment DD-4, section X(b)(ii), the Electric Distributor shall be responsible for compensating all Eligible New Large Loads that provided Interim Resource Adequacy Service for up to the amount of such service provided. The Electric Distributor shall be responsible for charging customers in its zone/area to fund any such compensation.
- (ii) The Electric Distributor may request the Office of the Interconnection to compensate certain Members for the provision of Interim Resource Adequacy Service and to assess charges on certain Load Serving Entities within the Electric Distributor's zone/area to fund such compensation. In support of such request, as further set forth in the PJM Manuals, the Electric Distributor shall (1) identify each Member to be compensated and provide the level of compensation and (2) identify each Load Serving Entity to be charged and the level of charge.
- (iii) The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to pay any amounts owed to another party under this section. In the event the Electric Distributor requests the Office of the Interconnection facilitate the billing associated with an Interim Resource Adequacy Event, such billing shall be considered a bilateral transaction between the Electric Distributor and the identified Members and PJMSettlement shall not be a contracting party to the settlement.
- (c) Nothing in this Tariff, Attachment DD-4, section X shall interfere with any Eligible New Large Load's election to (i) accept in its retail rates a sum less than 50% of the Non-Performance Charge Rate as compensation for the provision of wholesale Interim Resource Adequacy Service, or (ii) waive receipt in its retail rates any compensation for the provision of wholesale Interim Resource Adequacy Service.

[Tariff Record Data:](#)

Record Content Description	RAA ARTICLE 1
Tariff Record Title	RAA ARTICLE 1 -- DEFINITIONS
Record Version Number	57.0.0
Option Code	A
Record Narrative Name	RAA ARTICLE 1 -- DEFINITIONS
Tariff Record ID	206
Tariff Record Collation Value	917762046
Tariff Record Parent Identifier	205
Proposed Date	2026-10-12
Priority Order	1315
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Tariff or PJM Operating Agreement if not otherwise defined in this Agreement, for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

Accredited UCAP:

“Accredited UCAP” shall mean the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Accredited UCAP Factor:

“Accredited UCAP Factor” shall mean, through the 2024/2025 Delivery Year, one minus EFORD, and for 2025/2026 Delivery Year and subsequent Delivery Years, the ratio of the Capacity Resource’s Accredited UCAP to the Capacity Resource’s installed capacity.

Agreement:

“Agreement” shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

Annual Demand Resource:

“Annual Demand Resource” shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Annual Energy Efficiency Resource:

“Annual Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer and winter periods described in such Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast

prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Applicable Regional Entity:

“Applicable Regional Entity” shall have the same meaning as in the PJM Tariff.

Base Capacity Demand Resource:

“Base Capacity Demand Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through September of a Delivery Year, and will be available to the Office of the Interconnection for an unlimited number of interruptions during such months, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Base Capacity Demand Resource must be available June through September in the corresponding Delivery Year to be offered for sale or self-supplied in an RPM Auction, or included as a Base Capacity Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Base Capacity Energy Efficiency Resource:

“Base Capacity Energy Efficiency Resource” shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Base Capacity Resource:

“Base Capacity Resource” shall have the same meaning as in Tariff, Attachment DD.

Base Residual Auction:

“Base Residual Auction” shall have the same meaning as in Tariff, Attachment DD.

Behind The Meter Generation:

“Behind The Meter Generation” shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such

consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource or DER Capacity Aggregation Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Capability:

"Black Start Capability" shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Bring Your Own New Capacity:

"Bring Your Own New Capacity" or "BYONC" shall have the meaning provided in the Tariff.

Capacity Emergency Transfer Objective (CETO):

"Capacity Emergency Transfer Objective" or "CETO" shall mean, through the 2024/2025 Delivery Year, the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be, for Delivery Years through 2024/2025, calculated based in part on EFORD determined in accordance with Reliability Assurance Agreement, Schedule 5, Paragraph C. Beginning with the 2025/2026 Delivery Year, CETO shall mean the amount of electric energy that a given area must be able to import in order to satisfy a normalized expected unserved energy for the area that is equal to forty percent of the normalized expected unserved energy for the RTO when at the annual reliability criteria, where normalized expected unserved energy is the expected unserved energy (for the area or RTO, as appropriate) divided by the forecasted annual energy (for the area or RTO, as appropriate), when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Limit (CETL):

"Capacity Emergency Transfer Limit" or "CETL" shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Import Limit:

For any Delivery Year up to and including the 2019/2020 Delivery Year, "Capacity Import Limit" shall mean, (a) for the PJM Region, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines for each Delivery Year, through appropriate modeling and the application of engineering judgment, the transmission system can receive, in aggregate at the interface of the PJM Region with all external balancing authority areas and

deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus (2) the then-applicable Capacity Benefit Margin; and (b) for certain source zones identified in the PJM manuals as groupings of one or more balancing authority areas, (1) the maximum megawatt quantity of external Generation Capacity Resources that PJM determines the transmission system can receive at the interface of the PJM Region with each such source zone and deliver to load in the PJM Region under capacity emergency conditions without violating applicable reliability criteria on any bulk electric system facility of 100kV or greater, internal or external to the PJM Region, that has an electrically significant response to transfers on such interface, minus the then-applicable Capacity Benefit Margin times (2) the ratio of the maximum import quantity from each such source zone divided by the PJM total maximum import quantity. As more fully set forth in the PJM Manuals, PJM shall make such determination based on the latest peak load forecast for the studied period, the same computer simulation model of loads, generation and transmission topography employed in the determination of Capacity Emergency Transfer Limit for such Delivery Year, including external facilities from an industry standard model of the loads, generation, and transmission topography of the Eastern Interconnection under peak conditions. PJM shall specify in the PJM Manuals the areas and minimum distribution factors for identifying monitored bulk electric system facilities that have an electrically significant response to such transfers on the PJM interface. Employing such tools, PJM shall model increased power transfers from external areas into PJM to determine the transfer level at which one or more reliability criteria is violated on any monitored bulk electric system facilities that have an electrically significant response to such transfers. For the PJM Region Capacity Import Limit, PJM shall optimize transfers from other source areas not experiencing any reliability criteria violations as appropriate to increase the Capacity Import Limit. The aggregate megawatt quantity of transfers into PJM at the point where any increase in transfers on the interface would violate reliability criteria will establish the Capacity Import Limit. Notwithstanding the foregoing, a Capacity Resource located outside the PJM Region shall not be subject to the Capacity Import Limit if the Capacity Market Seller seeks an exception thereto by demonstrating to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) it has, at the time such exception is requested, met all applicable requirements to be pseudo-tied into the PJM Region, or the Capacity Market Seller has committed in writing that it will meet such requirements, unless prevented from doing so by circumstances beyond the control of the Capacity Market Seller, prior to the relevant Delivery Year;

(ii) at the time such exception is requested, it has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions; provided, however, that (a) the total megawatt quantity of all exceptions granted hereunder for a Delivery Year, plus the Capacity Import Limit for the applicable interface determined for such Delivery Year, may not exceed the total megawatt quantity of Network External Designated Transmission Service on

such interface that PJM has confirmed for such Delivery Year; and (b) if granting a qualified exception would result in a violation of the rule in clause (a), PJM shall grant the requested exception but reduce the Capacity Import Limit by the quantity necessary to ensure that the total quantity of Network External Designated Transmission Service is not exceeded.

Capacity Only Option:

“Capacity Only Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Capacity Performance Resource:

“Capacity Performance Resource” shall have the same meaning as in Tariff, Attachment DD.

Capacity Resources:

“Capacity Resources” shall mean megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of the Reliability Assurance Agreement, Schedules 9 and Reliability Assurance Agreement, Schedule 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the Reliability Assurance Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in such Schedules 9 and 10; or (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6; or (iv) generation and load reduction capability provided by a DER Capacity Aggregation Resource, pursuant to the procedures set forth in the Reliability Assurance Agreement, Schedule 6.2 and the PJM Manuals.

Capacity Resource Provider:

“Capacity Resource Provider” shall mean a Member that (1) owns, or has the contractual authority to control the output of, a Generation Capacity Resource, that has not transferred such authority to another entity; (2) or a DER Aggregator that has a contractual relationship to use a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource.

Capacity Storage Resource Class:

“Capacity Storage Resource Class” shall mean the ELCC Classes specified in Schedules 9.1 and 9.2, section B of this Agreement, each of which is composed of (1) Capacity Storage Resources with the same specified characteristic duration of 4, 6, 8, and 10 hours or; (2) storage device Component DER. The characteristic duration of an Energy Storage Resource Class is the ratio of

the modeled MWh energy storage capability of members of the class to the modeled MW power capability of members of the class.

Capacity Transfer Right:

“Capacity Transfer Right” shall have the meaning specified in Tariff, Attachment DD.

Coal Class:

“Coal Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by coal.

Combination Resource:

“Combination Resource” shall mean a Generation Capacity Resource, or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Compliance Aggregation Area (CAA):

“Compliance Aggregation Area” or “CAA” shall have the same meaning as in the Tariff.

Complex Hybrid Class:

“Complex Hybrid Class” shall mean an ELCC Class composed of Combination Resources that combine three or more components, whereby one component is a class of Limited Duration Resource, and the other components are different Variable Resource classes, and such Combination Resources cannot be included in any other Combination Resource class. A resource that is a member of a Complex Hybrid Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:

“Consolidated Transmission Owners Agreement,” “PJM Transmission Owners Agreement” or “Transmission Owners Agreement” shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Control Area:

“Control Area” shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Daily Unforced Capacity Obligation:

“Daily Unforced Capacity Obligation” shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with the Reliability Assurance Agreement, Schedule 8 or, as to an FRR Entity, in the Reliability Assurance Agreement, Schedule 8.1.

Delivery Year:

“Delivery Year” shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD or pursuant to an FRR Capacity Plan under RAA, Schedule 8.1.

Demand Resource (DR):

“Demand Resource” or “DR” shall mean a Limited Demand Resource, Extended Summer Demand Resource, Annual Demand Resource, Base Capacity Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan.

Demand Resource Factor or DR Factor:

“Demand Resource Factor” or “DR Factor” shall mean, for Delivery Years through May 31, 2018, that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource in accordance with Reliability Assurance Agreement, Schedule 6

Demand Resource Officer Certification Form:

“Demand Resource Officer Certification Form” shall mean a certification as to an intended Demand Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

Demand Resource Registration:

“Demand Resource Registration” shall mean a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with Tariff, Attachment K-Appendix, section 8.

Demand Resource Sell Offer Plan:

“Demand Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of Demand Resources in an RPM Auction, or an intended inclusion of Demand Resources in an FRR Capacity Plan.

Diesel Utility Class:

"Diesel Utility Class" shall mean an ELCC Class consisting of Unlimited Resources of the diesel technology type that is not primarily fueled by landfill gas.

DER Aggregator Officer Certification Form:

“DER Aggregator Officer Certification Form” shall mean a DER Aggregator’s certification as to an intended DER Capacity Aggregation Resource Sell Offer, in accordance with Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 and the PJM Manuals.

DER Capacity Aggregation Resource Sell Offer Plan:

“DER Capacity Aggregation Resource Sell Offer Plan” shall mean the plan required by Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1 in support of an intended offer of a DER Capacity Aggregation Resource in an RPM Auction, or an intended inclusion of a DER Capacity Aggregation Resource in an FRR Capacity Plan.

Effective Nameplate Capacity:

“Effective Nameplate Capacity” shall mean (i) for each Variable Resource and Combination Resource that is a Generation Capacity Resource, the resource’s Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output); (ii) for each Variable Resource and Combination Resource, that is an individual Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, the device’s maximum energy production capability, as defined by the resource’s state interconnection agreement; or (iii) for each Limited Duration Resource, the sustained level of output that the device can provide and maintain over a continuous period, whereby the duration of that continuous period matches the characteristic duration of the corresponding ELCC Class, with consideration given to ambient conditions expected to exist at the time of PJM system peak load, to the extent that such conditions impact such resource’s capability, not to exceed the Maximum Facility Output (or, for a Co-Located Resource, the applicable share of the Mixed Technology Facility’s Maximum Facility Output). For the 2025/2026 Delivery Year and subsequent Delivery Years, the Effective Nameplate Capacity of each Limited Duration Resource shall not exceed the greater of the Capacity Interconnection Rights of such Limited Duration Resource, or the transitional system capability as limited by the transitional resource MW ceiling as defined in the PJM Manuals, awarded for the applicable Delivery Year.

Effective UCAP:

“Effective UCAP” shall mean a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Class:

“ELCC Class” shall mean a defined group of ELCC Resources that share a common set of operational characteristics and for which effective load carrying capability analysis, as set forth in RAA, Schedules 9.1 and 9.2, will establish a unique ELCC Class UCAP and corresponding ELCC Class Rating(s). ELCC Classes shall be defined in the Schedules 9.1 and 9.2, section B of this Agreement. Members of an ELCC Class shall share a common method of calculating the ELCC Resource Performance Adjustment, provided that the individual ELCC Resource Performance Adjustment values will generally differ among ELCC Resources.

ELCC Class Rating:

“ELCC Class Rating” shall mean the rating factor, based on effective load carrying capability analysis, that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

ELCC Class UCAP:

“ELCC Class UCAP” shall mean the aggregate Effective UCAP all modeled ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Portfolio UCAP:

“ELCC Portfolio UCAP” shall mean the aggregate Effective UCAP that all modeled ELCC Resources are capable of providing in a given Delivery Year.

ELCC Resource:

“ELCC Resource” shall mean a Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, a Generation Capacity Resource or a Demand Resource.

ELCC Resource Performance Adjustment:

“ELCC Resource Performance Adjustment” shall mean the performance of a specific ELCC Resource relative to the aggregate performance of the ELCC Class to which it belongs as further described in RAA, Schedule 9.1, section F and RAA, Schedule 9.2, section D.

Electric Cooperative:

“Electric Cooperative” shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distributor:

“Electric Distributor” shall mean a Member that 1) owns or leases with rights equivalent to ownership of electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Emergency:

“Emergency” shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End-Use Customer:

“End-Use Customer” shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Members Committee sector classification, a Member that is a retail end-user that owns generation may qualify as an End-Use customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the

average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Efficiency Resource:

“Energy Efficiency Resource” shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of RAA, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the periods described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention. Annual Energy Efficiency Resources, Base Capacity Energy Efficiency Resources and Summer-Period Energy Efficiency Resources are types of Energy Efficiency Resources.

Exigent Water Storage:

“Exigent Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is not typically available during normal operating conditions (as those conditions are described in the relevant FERC hydropower license), but which can be drawn upon during emergency conditions (as described in the FERC hydropower license), including in order to avoid a load shed. In an effective load carrying capability analysis, exigent storage capability from an upstream hydro facility can be considered relative to a downstream hydro facility by assessing cascading storage and flows.

Existing Demand Resource:

“Existing Demand Resource” shall mean a Demand Resource for which the Demand Resource Provider has identified existing end-use customer sites that are registered for the current Delivery Year with PJM (even if not registered by such Demand Resource Provider) and that the Demand Resource Provider reasonably expects to have under a contract to reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such resource is offered.

Existing DER Capacity Aggregation Resource:

“Existing DER Capacity Aggregation Resource” shall mean a DER Capacity Aggregation Resource for which the DER Aggregator has identified existing Component DER that are registered in a DER Capacity Aggregation Resource for the current Delivery Year with PJM (even if not registered by such DER Aggregator) and that the DER Aggregator reasonably

expects to have under a contract to generate or reduce load based on PJM dispatch instructions by the start of the Delivery Year for which such DER Capacity Aggregation Resource is offered.

Existing Generation Capacity Resource:

“Existing Generation Capacity Resource” shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

Extended Summer Demand Resource:

“Extended Summer Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Facilities Study Agreement:

“Facilities Study Agreement” shall have the same meaning as in Tariff, Part VI, section 206.

FERC or Commission:

“FERC” or “Commission” shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Firm Point-To-Point Transmission Service:

“Firm Point-To-Point Transmission Service” shall have the meaning specified in the Tariff.

Firm Service Level:

“Firm Service Level” or “FSL” of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan. “Firm Service Level” or “FSL” of Demand Resource shall mean the pre-determined level to which an end-use customer’s load shall be reduced, upon notification from the Curtailment Service Provider’s market operations center or its agent.

Firm Transmission Service:

“Firm Transmission Service” shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement Alternative or FRR Alternative:

“Fixed Resource Requirement Alternative” or “FRR Alternative” shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in the Reliability Assurance Agreement, Schedule 8.1.

Fixed-Tilt Solar Class:

“Fixed-Tilt Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted in a fixed orientation.

Forecast Pool Requirement:

“Forecast Pool Requirement” or “FPR” shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Reliability Assurance Agreement, as approved by the PJM Board pursuant to Reliability Assurance Agreement, Schedule 4.1.

FRR Capacity Plan or FRR Plan:

“FRR Capacity Plan” or “FRR Plan” shall mean a long-term plan for the commitment of Capacity Resources and Price Responsive Demand to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in the Reliability Assurance Agreement, Schedule 8.1.

FRR Entity:

“FRR Entity” shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

FRR Service Area:

“FRR Service Area” shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Program Option:

“Full Program Option” shall mean participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Tariff, Attachment DD and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for the ability to reduce load during a pre-emergency or emergency event.

Full Requirements Service:

“Full Requirements Service” shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Gas Combined Cycle Class:

“Gas Combined Cycle Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combined Cycle Dual Fuel Class.

Gas Combined Cycle Dual Fuel Class:

“Gas Combined Cycle Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combined cycle technology type that is primarily fueled by natural gas, and that attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Gas Combustion Turbine Class:

“Gas Combustion Turbine Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, but does not meet the requirements to be included in the Gas Combustion Turbine Dual Fuel Class.

Gas Combustion Turbine Dual Fuel Class:

“Gas Combustion Turbine Dual Fuel Class” shall mean an ELCC Class consisting of Unlimited Resources of the combustion turbine technology type that is primarily fueled by natural gas, and attests that it has the capability to start independently using onsite sources and operate independently on alternate onsite fuel source(s) up to its maximum capacity level during the winter season of the applicable Delivery Year in which it is providing capacity, and capable of operating on the alternate fuel for two 16-hour periods over two consecutive days at its maximum capacity level.

Generation Capacity Resource:

“Generation Capacity Resource” shall mean a Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner:

“Generation Owner” shall mean a Member that owns or leases with rights equivalent to ownership, or otherwise controls and operates one or more operating generation resources located in the PJM Region. The foregoing notwithstanding, for a planned generation resource to qualify a Member as a Generation Owner, such resource shall have cleared an RPM auction, and for Energy Resources, the resource shall have a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM. Purchasing all or a portion of the output of a generation resource shall not be sufficient to qualify a Member as a Generation Owner. For purposes of Members Committee sector classification, a Member that is primarily a retail end-user of electricity that owns generation may qualify as a Generation Owner if: (1) the generation resource is the subject of a FERC-jurisdictional interconnection agreement or wholesale market participation agreement within PJM; (2) the average physical unforced capacity owned by the Member and its affiliates over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average PJM capacity obligation of the Member and its affiliates over the same time period; and (3) the average energy produced by the Member and its affiliates within PJM over the five Planning Periods immediately preceding the relevant Planning Period exceeds the average energy consumed by the Member and its affiliates within PJM over the same time period.

Generator Forced Outage:

“Generator Forced Outage” shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

Generator Maintenance Outage:

“Generator Maintenance Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

Generator Planned Outage:

“Generator Planned Outage” shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

Good Utility Practice:

“Good Utility Practice” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).

Hybrid Resource Class:

“Hybrid Resource Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 Section B. Each Hybrid Resource Class has a specified combination of two components, whereby, absent being part of a Combination Resource, the individual components would be in a Capacity Storage Resource Class, a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of a Hybrid Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Hydropower With Non-Pumped Storage:

“Hydropower With Non-Pumped Storage” shall mean a hydropower facility that can capture and store incoming stream flow, without use of pumps, in pondage or a reservoir, and the Generation

Owner has the ability, within the constraints available in the applicable operating license, to exert material control over the quantity of stored water and output of the facility throughout an Operating Day.

Hydropower With Non-Pumped Storage Class:

“Hydropower With Non-Pumped Storage Class” shall mean an ELCC Class consisting of Combination Resources that are Hydropower With Non-Pumped Storage resources.

Incremental Auction:

“Incremental Auction” shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

- (i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, Accredited UCAP Factor decrease, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and
- (ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

Intermittent Hydropower Class:

“Intermittent Hydropower Class” shall mean an ELCC Class consisting of Variable Resources that are run-of-river hydropower generators that must generally pass incoming water and therefore cannot appreciably store water to later increase the output of the facility. Resources in the Intermittent Hydropower Class are not Hydropower with Non-Pumped Storage resources.

IOU:

“IOU” shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Intermittent Landfill Gas Class:

“Intermittent Landfill Gas Class” shall mean an ELCC Class consisting of Variable Resources fueled by landfill gas that, because of fuel availability patterns, cannot run consistently at installed capacity levels for 24 or more hours.

Large Load:

“Large Load” shall mean end-use customer(s) load that has a cumulative peak load of 50 megawatts or greater at a single electrical site behind one or more points of interconnection, where for configurations involving multiple affiliated load facilities or multiple points of interconnection with affiliated load facilities behind them, all affiliated load facilities within a one-mile radius will be considered a single electrical site as further described in the PJM Manuals.

Large Load Adjustment:

“Large Load Adjustment” shall mean any MW quantity of adjustments to summer peak load at the “zone/area” level and summed by Zone as further detailed in PJM Manuals. For purposes of this definition, a “zone/area” is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering (e.g., the service territory of an operating company of a Transmission Owner).

Limited Demand Resource:

“Limited Demand Resource” shall mean, for Delivery Years through May 31, 2018, and for FRR Capacity Plans Delivery Years through May 31, 2019, a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 Load Management Events during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Limited Duration Resource:

“Limited Duration Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Serving Entity or LSE:

“Load Serving Entity” or “LSE” shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

Locational Reliability Charge:

“Locational Reliability Charge” shall mean the charge determined pursuant to RAA, Article 7, section 2.

Markets and Reliability Committee:

“Markets and Reliability Committee” shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

Maximum Emergency Service Level:

“Maximum Emergency Service Level” or “MESL” of Price Responsive Demand for the 2017/2018 through the 2021/2022 Delivery Years shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

Member:

“Member” shall have the meaning provided in the Operating Agreement.

Members Committee:

“Members Committee” shall mean the committee specified in Operating Agreement, section 8 composed of the representatives of all the Members.

NERC:

“NERC” shall mean the North American Electric Reliability Corporation or any successor thereto.

Network External Designated Transmission Service:

“Network External Designated Transmission Service” shall mean the quantity of network transmission service confirmed by PJM for use by a market participant to import power and

energy from an identified Generation Capacity Resource located outside the PJM Region, upon demonstration by such market participant that it owns such Generation Capacity Resource, has an executed contract to purchase power and energy from such Generation Capacity Resource, or has a contract to purchase power and energy from such Generation Capacity Resource contingent upon securing firm transmission service from such resource.

Network Resources:

“Network Resources” shall have the meaning set forth in the PJM Tariff.

Network Transmission Service:

“Network Transmission Service” shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Nominal PRD Value:

“Nominal PRD Value” shall mean, as to any PRD Provider, an adjustment, determined in accordance with Reliability Assurance Agreement, Schedule 6.1, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

Nominated Demand Resource Value:

“Nominated Demand Resource Value” shall have the meaning specified in Tariff, Attachment DD.

Non-Retail Behind the Meter Generation:

“Non-Retail Behind the Meter Generation” shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Nuclear Class:

“Nuclear Class” shall mean an ELCC Class consisting of Unlimited Resources primarily fueled by nuclear fuel.

Obligation Peak Load:

“Obligation Peak Load” shall have the meaning specified in Reliability Assurance Agreement, Schedule 8.

Office of the Interconnection:

“Office of the Interconnection” shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

Offshore Wind Class:

“Offshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with offshore wind turbines located in the ocean.

Onshore Wind Class:

“Onshore Wind Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy using wind turbines and that are not in the Offshore Wind Class.

Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

“Operating Agreement of the PJM Interconnection, L.L.C.,” “Operating Agreement” or “PJM Operating Agreement” shall mean that agreement, dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements hereto, as amended from time to time thereafter, among the Members of the PJM Interconnection, L.L.C, on file with the Commission.

Operating Day:

“Operating Day” shall have the same meaning as provided in the Operating Agreement.

Operating Reserve:

“Operating Reserve” shall mean the amount of generating capacity scheduled to be available for a specified period of an Operating Day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

Ordinary Water Storage:

“Ordinary Water Storage” shall mean water stored in the pondage or reservoir of a hydropower resource which is typically available during normal operating conditions pursuant to the FERC license governing the operation of the hydropower resource.

Other Limited Duration Class:

“Other Limited Duration Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B of this Agreement, each of which has a specified characteristic duration and consists of Limited Duration Resources that are not Capacity Storage Resources. The

characteristic duration of an Other Limited Duration Class is the maximum period of time represented in the ELCC model that the resources of the class can run at a stated capability.

Other Limited Duration Combination Class:

“Other Limited Duration Combination Class” shall mean the ELCC Classes specified in RAA Schedules 9.1 and 9.2 section B. Each Other Limited Duration Class has a specified combination of two components, whereby, absent being part of a Combination Resource, one component would be in an Other Limited Duration Class, and the other component would be in a Variable Resource Class or would be an Unlimited Resource. A resource that is a member of an Other Limited Duration Combination Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Other Supplier:

“Other Supplier” shall mean a Member that: (i) is engaged in buying, selling or transmitting electric energy, capacity, ancillary services, Financial Transmission Rights or other services available under PJM’s governing documents in or through the Interconnection or has a good faith intent to do so, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

Other Unlimited Resource Class:

“Other Unlimited Resource Class” shall mean an ELCC Class consisting of Unlimited Resources that do not qualify for any other ELCC Class specified in RAA Schedule 9.2, section D.

Other Variable Resource Class:

“Other Variable Resource Class” shall mean an ELCC Class consisting of Variable Resources that are not in any other Variable Resource class, including Variable Resources that are composed of multiple components, each of which would be a Variable Resource. A resource composed of both fixed-tilt solar panels and tracking solar panels is not in this class. A resource that is a member of a Other Variable Resource Class has a single Point Of Interconnection, unless the resource is controlled in an integrated fashion, is at a single site, and is approved by PJM to be considered a single resource in accordance with the PJM Manuals.

Partial Requirements Service:

“Partial Requirements Service” shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Party:

“Party” shall mean an entity bound by the terms of the Operating Agreement.

Peak Shaving Adjustment:

“Peak Shaving Adjustment” shall mean a load forecast mechanism that allows load reductions by end-use customers to result in a downward adjustment of the summer load forecast for the associated Zone. Any End-Use Customer identified in an approved peak shaving plan shall not also participate in PJM Markets as Price Responsive Demand, Demand Resource, Base Capacity Demand Resource, Capacity Performance Demand Resource, or Economic Load Response Participant.

Percentage Internal Resources Required:

“Percentage Internal Resources Required” shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

Performance Assessment Interval:

“Performance Assessment Interval” shall have the meaning specified in Tariff, Attachment DD.

PJM:

“PJM” shall mean PJM Interconnection, L.L.C., including the Office of the Interconnection as referenced in the PJM Operating Agreement. When such term is being used in the RAA it shall also include the PJM Board.

PJM Board:

“PJM Board” shall mean the Board of Managers of the LLC, acting pursuant to the Operating Agreement, except when such term is being used in Tariff, Attachment M, in which case PJM Board shall mean the Board of Managers of PJM or its designated representative, exclusive of any members of PJM Management.

PJM Governing Agreements:

“PJM Governing Agreements” shall have the meaning provided in the Operating Agreement.

PJM Manuals:

“PJM Manuals” shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

PJM Region:

“PJM Region” shall have the same meaning as provided in the Operating Agreement.

PJM Region Installed Reserve Margin:

“PJM Region Installed Reserve Margin” shall mean the percent installed reserve margin for the PJM Region required pursuant to Reliability Assurance Agreement, Schedule 4.1, as approved by the PJM Board.

PJM Tariff, Tariff, O.A.T.T., OATT or PJM Open Access Transmission Tariff:

“PJM Tariff,” “Tariff,” “O.A.T.T.,” “OATT” or “PJM Open Access Transmission Tariff” shall mean that certain PJM Open Access Transmission Tariff, including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time thereafter.

Planned Demand Resource:

“Planned Demand Resource” shall mean any Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6. As set forth in Reliability Assurance Agreement, Schedule 6 and Reliability Assurance Agreement, Schedule 8.1, a Demand Resource Provider submitting a DR Sell Offer Plan shall identify as Planned Demand Resources in such plan all Demand Resources in excess of those that qualify as Existing Demand Resources.

Planned DER Capacity Aggregation Resource:

A “Planned DER Capacity Aggregation Resource” shall mean any DER Capacity Aggregation Resource that does not currently have the capability to provide generation or reduction in demand, but that is scheduled to be capable of providing such generation or reduction in demand on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Reliability Assurance Agreement, Schedule 6.2. As set forth in Reliability Assurance Agreement, Schedule 6.2 and Reliability Assurance Agreement, Schedule 8.1, a DER Aggregator submitting a DER Capacity Aggregation Resource Sell Offer Plan shall identify in such plan all DER Capacity Aggregation Resources in excess of those that qualify as Existing DER Capacity Aggregation Resources. A Planned DER Capacity Aggregation Resource must comply with all provisions of the DER Aggregator Participation Model described in Tariff, Attachment K-Appendix, section 1.4B and Operating Agreement, Schedule 1, section 1.4B, prior to the applicable Delivery Year.

Planned External Generation Capacity Resource:

“Planned External Generation Capacity Resource” shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the

Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Base Residual Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has documentation which is functionally equivalent to an approved Decision Point I submission under the PJM Tariff Part VII or VIII as applicable or, for resources which are greater than 20MWs participating in a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, an agreement or other documentation which is functionally equivalent to an approved Decision Point II submission under the PJM Tariff Part VII or VIII as applicable, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. Prior to participating in any Incremental Auction for such Delivery Year, the Capacity Market Seller must demonstrate it has entered into an interconnection agreement, or such other documentation that is functionally equivalent to a Generation Interconnection Agreement under the PJM Tariff, with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and, as applicable, the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to be delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. Any such resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

Planned Generation Capacity Resource:

“Planned Generation Capacity Resource” shall mean a Generation Capacity Resource, or additional megawatts to increase the size of a Generation Capacity Resource that is being or has been modified to increase the number of megawatts of available installed capacity thereof, participating in the generation interconnection process under Tariff, Part IV, Subpart A, Part VII or Part VIII, as applicable, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Capacity Plan; (ii) for any such resource seeking to offer into a Base Residual Auction, or for any such resource of 20 MWs or less seeking to offer into a Base Residual Auction, all the requirements for an approved Decision Point I submission have been met under Tariff Part VII or VIII (or, for resources for which a Decision Point I submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point I submission) prior to the Base Residual Auction for such Delivery Year; (iii) for any such resource of more than 20 MWs seeking to offer into a Base Residual Auction for the 2019/2020 Delivery Year and subsequent Delivery Years, all the requirements for an approved Decision Point II submission have been met under Tariff Part VII or VIII (or, for resources for

which a Decision Point II submission is not required, has such other agreement or documentation that is functionally equivalent to an approved Decision Point II submission) has been executed prior to the Base Residual Auction for such Delivery Year; and (iv) a Generation Interconnection Agreement or Wholesale Market Participation Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years.

Planning Period:

“Planning Period” shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

Portfolio Expected Unserved Energy:

“Portfolio Expected Unserved Energy” shall mean the annual amount of expected unserved energy, in MWh, that is expected for the RTO when at the annual reliability criteria that provides an acceptable level of reliability consistent with the Reliability Principles and Standards.

PRD Curve:

“PRD Curve” shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

PRD Provider:

“PRD Provider” shall mean a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for and provides Price Responsive Demand.

PRD Provider’s Zonal Expected Peak Load Value of PRD:

“PRD Provider’s Zonal Expected Peak Load Value of PRD” shall mean the expected contribution to Delivery Year peak load of a PRD Provider’s Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year’s peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection’s load forecasts used for purposes of the RPM Auctions.

PRD Reservation Price:

“PRD Reservation Price” shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

PRD Substation:

“PRD Substation” shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

Price Responsive Demand:

“Price Responsive Demand” or “PRD” shall mean end-use customer load registered by a PRD Provider pursuant to Reliability Assurance Agreement, Schedule 6.1 that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Performance Assessment Interval that triggers a PRD performance assessment or a Non-PAI Event, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

Price Responsive Demand Credit:

“Price Responsive Demand Credit” shall mean a credit, based on committed Price Responsive Demand, as determined under Reliability Assurance Agreement, Schedule 6.1.

Price Responsive Demand Plan or PRD Plan:

“Price Responsive Demand Plan” or “PRD Plan” shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Reliability Assurance Agreement, Schedule 6.1 and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider’s Nominal PRD Value.

Public Power Entity:

“Public Power Entity” shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrades:

“Qualifying Transmission Upgrades” shall have the meaning specified in Tariff, Attachment DD.

Relevant Electric Retail Regulatory Authority:

“Relevant Electric Retail Regulatory Authority” or “RERRA” shall have the meaning specified in the PJM Operating Agreement.

Reliability Principles and Standards:

“Reliability Principles and Standards” shall mean the principles and standards established by the Office of the Interconnection that define, among other things, an acceptable probabilistic of loss of load criteria due to inadequate generation or transmission capability, as amended from time to time.

Required Approvals:

“Required Approvals” shall mean all of the approvals required for the Operating Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of the Operating Agreement.

Self-Supply:

“Self-Supply” shall have the meaning provided in Tariff, Attachment DD.

Small Commercial Customer:

“Small Commercial Customer” shall have the same meaning as in the PJM Tariff.

State Consumer Advocate:

“State Consumer Advocate” shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Regulatory Structural Change:

“State Regulatory Structural Change” shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example,

without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

Steam Class:

"Steam Class" shall mean an ELCC Class consisting of Unlimited Resources of the steam technology type and the primary fuel is not coal or nuclear.

Summer-Period Demand Resource:

Summer-Period Demand Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a resource that is placed under the direction of the Office of the Interconnection, and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as a Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

Summer-Period Energy Efficiency Resource:

Summer-Period Energy Efficiency Resource shall mean, for the 2020/2021 Delivery Year and subsequent Delivery Years, a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Reliability Assurance Agreement, Schedule 6 and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during the summer peak periods as described in Reliability Assurance Agreement, Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Summer-Period Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Supervisory Control:

"Supervisory Control" shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of the Operating Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

Threshold Quantity:

“Threshold Quantity” shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD through the 2024/2025 Delivery Year, or pool-wide average Accredited UCAP Factor effective with the 2025/2026 Delivery Year) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be determined in accordance with Reliability Assurance Agreement, Schedule 8.1, section D.2.

Tracking Solar Class:

“Tracking Solar Class” shall mean an ELCC Class consisting of Variable Resources that produce electrical energy with solar panels that are primarily mounted on trackers that align the panels with incoming sunlight over the course of the day.

Transmission Facilities:

“Transmission Facilities” shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner:

“Transmission Owner” shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity:

“Unforced Capacity” shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

Unlimited Resource:

“Unlimited Resource” shall mean a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource:

“Variable Resource” shall mean a Generation Capacity Resource or a generation Component DER within a DER Aggregation Resource that is linked to a DER Capacity Aggregation Resource, with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Winter Peak Load (or WPL):

“Winter Peak Load” or “WPL” shall mean the average of the Demand Resource customer’s specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand values may be excluded from the calculation. Upon approval by the Office of the Interconnection, a Curtailment Service Provider may provide alternative data to calculate Winter Peak Load, as outlined in the PJM Manuals, when there is insufficient hourly load data for the two Delivery Years prior to the relevant Delivery Year or if more than two days meet the exclusion criteria described above.

Zonal Capacity Price:

“Zonal Capacity Price” shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

Zone or Zonal:

“Zone” or “Zonal” shall refer to an area within the PJM Region, as set forth in Tariff, Attachment J and RAA, Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load located outside the PJM Region that is served from such Zone under Tariff, Attachment H-A.

Zonal Winter Weather Adjustment Factor (ZWWAF):

“Zonal Winter Weather Adjustment Factor” or “ZWWAF” shall mean the PJM zonal winter weather normalized coincident peak divided by PJM zonal average of 5 coincident peak loads in December through February.

Tariff Record Data:

Record Content Description	RAA Article 7 Sec 8
Tariff Record Title	RAA Article 7 Section 8 - Requirement to Designate Network
Record Version Number	0.0.0
Option Code	A
Record Narrative Name	RAA Article 7 Section 8 - Requirement to Designate Network Resources to Serve Capacity Needs for New Large Loads and Conditional Requirement to Provide Interim Resource Adequacy Service
Tariff Record ID	2357
Tariff Record Collation Value	930634000
Tariff Record Parent Identifier	217
Proposed Date	2026-10-12
Priority Order	500
Record Change Type	NEW
Record Content Type	4
Associated Filing Identifier	

7.8 Requirement to Designate Network Resources to Serve Capacity Needs for New Large Loads and Conditional Requirement to Provide Interim Resource Adequacy Service

Effective June 1, 2027, each LSE that desires to provide Network Transmission Service to support New Large Loads must designate one or more Generation Capacity Resources or Capacity Storage Resources that had not cleared an RPM Auction as Network Resource(s) in a cumulative amount that equals or exceeds the LSE's New Large Load's peak load (in MW) as reported in the Large Load Registry pursuant to RAA, Schedule 11 or such New Large Load may be subject to load reduction requests during Emergencies prior to Pre-Emergency Load Management Response. If, on June 1, 2027, an LSE has not so designated such Network Resource(s) as BYONC with which it has entered into an arrangement in accordance with this requirement and Tariff, Attachment DD-4, then the amount of New Large Load that is the difference between its reported peak load and its designated Bring Your Own New Capacity and assigned Allocated RBP UCAP MW will be subject to the rates, terms, and conditions of Interim Resource Adequacy Service, as set forth in Tariff, Attachment DD-4.

Tariff Record Data:

Record Content Description	RAA SCHEDULE 8.1.D
Tariff Record Title	RAA SCHEDULE 8.1.D-FRR Capacity Plans
Record Version Number	16.0.0
Option Code	A
Record Narrative Name	RAA SCHEDULE 8.1.D-FRR Capacity Plans
Tariff Record ID	285
Tariff Record Collation Value	974255183
Tariff Record Parent Identifier	281
Proposed Date	2026-10-12
Priority Order	610
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

1.1 Beginning with the 2020/2021 Delivery Year and for all subsequent Delivery Years, the FRR Capacity Plan shall comprise only Capacity Performance Resources and Seasonal Capacity Performance Resources. An FRR Entity may not include in its FRR Capacity Plan any MW quantity of Existing Generation Capacity Resource in excess of what such FRR Entity owned or contracted by such FRR Entity prior to June 1, 2027, to serve New Large Load.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the Base Zonal FRR Scaling Factor times the summation of the FRR Entity's MW share of the Zonal Weather Normalized Summer Peak last determined prior to the Base Residual Auction for such Delivery Year plus the Obligation Peak Load MW associated with any Load Adjustment specified for such Delivery Year for any "zone/area" served by the FRR Entity's Capacity Plan. The Obligation Peak Load MW associated with a Load Adjustment specified for a "zonal/area" is determined as set forth in RAA, Schedule 8, section B.

The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand

must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal $[(ZPLDY - ZLA) / ZWN\text{SP}]$, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year;

ZLA = the Zonal MW quantity of Load Adjustment for such Delivery Year; and

ZWN\text{SP} = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement, the PJM Tariff, and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan, subject to applicable demand resource constraints for the relevant Delivery Year, submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity. Without limiting the generality of the foregoing, the FRR Entity must submit a Demand Resource Sell Offer Plan 15 business days before the deadline for submitting an FRR Capacity Plan as to any Demand Resources it intends to include in such FRR Capacity Plan and may only include in such FRR Capacity Plan Demand Resources that are approved by PJM following review of such Demand Resource Sell Offer Plan. The requirements, standards, and procedures for a Demand Resource Sell Offer Plan shall be as set forth in Schedule 6 of this Agreement, provided that all references (including deadlines) in Schedule 6, section A-1 to submission or clearing of a Demand Resource offer in an RPM

Auction shall be understood for purposes of FRR Entities as referring to inclusion of a Demand Resource in an FRR Capacity Plan, and a distinct Demand Resource Officer Certification Form shall be applicable to FRR Entities, as shown in the PJM Manuals and provided on the PJM website.

5. For each LDA for which the Office of the Interconnection is required to establish a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a Percentage Internal Resources Required, subject to subsections D.1.1 and D.2 of this Schedule. The Percentage Internal Resources Required will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement. Notwithstanding the provisions of Sections C.1 and C.2 of this Schedule 8.1, an FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of its minimum five year FRR commitment for which the Office of the Interconnection will be required to establish a separate Variable Resource Requirement Curve by giving written notice two months prior to the Base Residual Auction for the Delivery Year. The Office of the Interconnection shall be deemed to be required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is the Eastern Mid-Atlantic Region (“EMAR”), Southwest Mid-Atlantic Region (“SWMAR”), or Mid-Atlantic Region (“MAR”), or for other LDAs if the separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the Tariff.

6. An FRR Entity may reduce the Percentage Internal Resources Required as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the CETL for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party’s capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days *after* the submittal *deadline* of the FRR Capacity Plan. Through the 2024/2025 Delivery Year, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in \$/MW-day, times the shortfall of

Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, if the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to the price level corresponding to point (1) of the Variable Resource Requirement curve, as provided in Tariff, Attachment DD, section 5.10(a)(i), for the relevant Locational Deliverability Area, in \$/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for such Delivery Year.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement, the PJM Tariff, and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

Tariff Record Data:

Record Content Description	RAA SCHEDULE 11
Tariff Record Title	RAA SCHEDULE 11
Record Version Number	2.0.0
Option Code	A
Record Narrative Name	RAA SCHEDULE 11DATA SUBMITTALS
Tariff Record ID	293
Tariff Record Collation Value	980691110
Tariff Record Parent Identifier	205
Proposed Date	2026-10-12
Priority Order	510
Record Change Type	CHANGE
Record Content Type	4
Associated Filing Identifier	

SCHEDULE 11

DATA SUBMITTALS

A. To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.
2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.
3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.
4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

B. 1. (a) Each Party shall submit, or cause to be submitted, to the Office of the Interconnection the following information, as may be further described in the PJM Manuals, related to each Large Load served by the Party:

- Eligible Customer/Network Customer for Large Load;
- Description of Large Load;
- Location(s) (Control Zone, Electric Distributor zone/area, where a zone/area is an area within a Zone for which the relevant Electric Distributor specifies a separate Obligation Peak Load MW value. A zone/area is a service area of an Electric Distributor that is a separately identifiable, geographic area bounded by wholesale metering);
- In-service date for each increment of load;
- Peak shaving adjustment value pursuant to a state program codified in state law and whether and how it meets the requirements of Tariff, Attachment DD-2;
- Delivery point / Point(s) of interconnection (include all if more than one);
- Peak load quantity (MW) and ramp schedule, if applicable;

- Telemetry specifications;
- BYONC quantity (MW) and ramp schedule, if applicable;
- Allocated RBP UCAP MW quantity (MW), if applicable;
- Backup generation (MW), including fuel type and relevant permitting limitations;
- Contracts or service agreements between the Large Load and the LSE;
- Points of contact at the applicable Transmission Owner, Electric Distributor, and Load Serving Entity;
- EMS B1/B2/B3 name (for the applicable Transmission Owner, Electric Distributor); and
- Additional details and contents as necessary, in accordance with the PJM Manuals.

(b) The Parties acknowledge that information related to the development and maintenance of the Large Load Registry may be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement and the Tariff.

(c) The Office of the Interconnection may review information and coordinate with the applicable Transmission Owner and Electric Distributor as needed, regarding the validity of the information provided, including through requesting additional information as the Office of the Interconnection deems necessary, as further set forth in the PJM Manuals. The Office of the Interconnection also may consult with the Large Load.

(d) Based on the information provided, or caused to be provided, by each Party, as well as other information provided by, for example, Electric Distributors, the Office of the Interconnection shall maintain a registry of all Large Loads, and update it periodically. To the extent such documents, data, or other information provided to the Office of the Interconnection has been designated as confidential by a Party, Electric Distributor, or other entity supplying the information, the Office of the Interconnection shall maintain the confidentiality of the information provided under this RAA, Schedule 11, section B consistent with its obligations under Operating Agreement, section 18.17. Information maintained in the Large Load registry may be available to Authorized Commissions, Transmission Owners, Electric Distributors, Load Serving Entities, the Market Monitoring Unit, and FERC subject to appropriate data protection safeguards required by Operating Agreement, section 18.17.

(e) The Office of the Interconnection shall post aggregate data from the Large Load Registry on the PJM website, aggregated by Electric Distributor zone/area, where possible and in a manner consistent with existing confidentiality protections in the PJM Governing Agreements.

2. (a) Each Party serving or contracted to serve a Large Load that is or will be in service prior to June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection by March 1, 2027.

(b) Each Party serving or contracted to serve a New Large Load that will be in service on or after June 1, 2027, shall provide the information required by RAA, Schedule 11.B.1 to the Office of the Interconnection before the in-service date of the Large Load.

(c) Each Party contracted to serve a New Large Load shall provide the location(s) as required by RAA, Schedule 11.B.1 to the Office of the Interconnection before determination of the final PJM Regional Peak Load Forecast for the effective RPM Auction for the Delivery Year in which the New Large Load is expected to be in-service starting with the 2028 PJM Regional Peak Load Forecast.

Each Party shall promptly inform the Office of the Interconnection of any change in the information required by RAA, Schedule 11.B.1 with respect to a Large Load served by the Party, including whether the Party no longer serves the Large Load or has acquired the contractual right to serve a registered Large Load.

3. The information provided pursuant to RAA, Schedule 11, section B will be used, to the extent necessary, for purposes including but not limited to implementation of Interim Resource Adequacy Service, which is a load reduction service, effective starting with the 2027/2028 Delivery Year, through which Eligible New Large Loads may be compensated for providing load reductions requested by the Office of the Interconnection to maintain system reliability for the purpose of supporting the integration of New Large Loads to the PJM Region that have not entered into an arrangement with new capacity additions to the PJM Region, as more fully set forth in Tariff, Attachment DD-4.

Document Content(s)

IRAS Transmittal Letter 4929-0395-4887 v.3.pdf 1

Attachment A- Marked Tariff 4919-3670-8807 v.1.pdf.....133

Attachment B- Clean Tariff 4930-8837-2935 v.2.pdf.....278

Attachment C IRAS - Pulong Affidavit .pdf.....423

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EXHIBIT I

Essential Action to Industry

Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control

Initial Distribution: May 4, 2026

The purpose of this Level 3 NERC Alert is to ensure Essential Actions are taken by registered entities to address the risks posed by existing and new computational loads¹ interacting with the bulk power system (BPS), inclusive of computational load interconnecting with collocated generation.²

NERC issued a previous Level 2 Alert Industry Recommendation: *Large Load Interconnection, Study, Commissioning, and Operations*³ that discussed the recommended practices that NERC deemed necessary to address the emerging risks from large loads. In the responses provided to the Alert, NERC found that entities generally did not have sufficient processes, procedures, or methods to address risks associated with computational loads. This contrasts with the robust historical experience with traditional non-power electronic non-computational load. As seen in the public report, NERC found specific deficiencies with the treatment of computational loads. Examples of this load include artificial intelligence training, cryptocurrency mining, and traditional data center uses.

As stated in the public report, NERC determined a set of immediate actions that registered entities should take to reduce the risk to the BPS that warrant issuance of this Level 3 alert. These actions relate to the modeling, study, installed fault recording or instrumentation, commissioning, operation, protection, and control of computational load.

NERC issues this Level 3 Alert for entities to implement specific changes⁴ to handle critical risks. Additional actions are discussed as part of NERC's Large Loads Action Plan and include the draft registry criteria⁵ and Standard Authorization Request (SAR) for computational load⁶ posted on NERC's website on April 1, 2026. Responses will also help

¹ NERC is currently working to register a "Computational Load Entity" for these loads. Currently, this would include loads that are 20 MW and greater, connected at 60kV, and contain more than 1 MW of IT Load. More information is available on NERC's [Rules of Procedure](#) webpage.

² Colocation with generation is one significant way computational load is interacting and using the BPS.

³ See [Aggregated Report on NERC Level 2 Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations](#) to see the results of the previous Level 2 Alert.

⁴ As indicated in the public level 2 alert report, entities that do not have and do not expect to integrate computational loads within two years may not find it useful to implement these Essential Actions. These Essential Actions are for those entities that have or could expect to have computational loads or that may include these loads in the next two years. This includes entities that do not have computational load in their territory but could feasibly receive a request for one. Entities should implement these Essential Actions prior to receiving a computational load interconnection request.

⁵ More information is available on NERC's [Rules of Procedure](#) webpage.

⁶ More information is available on the [Project 2026-02](#) webpage.

inform potential future standards revisions developed in coordination with NERC's Large Loads Working Group of the Reliability and Security Technical Committee.

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[About NERC Alerts >>](#)

Status:	Acknowledgement Required by Midnight Eastern on May 11, 2026 Reporting Required by Midnight Eastern on August 3, 2026
	PUBLIC: No Restrictions More on handling >>
Instructions:	This Level 3 NERC Alert provides specific Essential Actions that NERC registered entities should consider in response to a particular issue. Pursuant to Rule 810 of NERC's Rules of Procedure,⁷ NERC registered entities shall (1) acknowledge receipt of this advisory within the NERC Alert System, and (2) report to NERC on the status of their activities in relation to this Essential Action (as provided below). For United States entities, NERC will aggregate the responses and provide an anonymized report to Federal Energy Regulatory Commission (FERC) as required under Rule 810. This Level 3 NERC Alert is not the same as a Reliability Standard, and it does not create a mandatory obligation to take the Essential Actions. Your organization will not be subject to penalties for failure to implement the Essential Actions. Issuance of this Essential Action, however, does not alter the requirements of any approved Reliability Standard or excuse the failure to follow the practices discussed in the Essential Action if such failure constitutes a violation of a Reliability Standard. Registered entities must continue to comply with applicable Reliability Standards.
Distribution:	Initial Distribution: Transmission Planner (TP), Planning Coordinator (PC), Transmission Owner (TO), Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) Who else will get this alert? >>
Primary Interest Groups:	Transmission Planning, Generation Engineering, Generation Operations, System Operators, System Operators – System Protection, System Operators – Transmission Engineering

⁷ <https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>

Essential Action:

Essential Actions are specific actions that NERC has determined to be essential for certain segments of owners, operators, or users of the BPS to undertake to ensure the Reliable Operation of the BPS. Pursuant to Rule 810 of NERC's Rules of Procedure (ROP),⁸ NERC registered entities shall (1) acknowledge receipt of these Essential Actions within the NERC Alert System, and (2) report to NERC on the status of their activities in relation to these Essential Actions (as provided below). Confidential Information shall be protected in accordance with the provisions of Section 1500 of the ROP. As emphasized in Section 810, for example, NERC's report to FERC regarding actions taken in response to this Alert will include "appropriate protection for Confidential Information or Critical Energy Infrastructure Information."⁹

Similarly, any public report with findings from this Alert will ensure appropriate protections under Section 1500 of the ROP.

Essential Action #1

TPs and PCs should develop a detailed list of modeling data, settings, and parameters needed from computational loads and distribute this to TOs in their footprint. TOs should reflect this in their facility interconnection requirements.¹⁰ TPs and PCs should use the *PERC1* (Power Electronic Reconnecting and Ceasing)¹¹ model, or a model with equivalent or better capabilities, at minimum, as a base for these requirements.¹² Power electronic drives supplying cooling loads should also be represented with an appropriate model. Additionally, TPs and PCs should do the following:

1. Model the computational load records separate from other industrial loads. Model the computational load facility's Information Technology (IT) load separate from the non-IT load (see item 2.c. below).
2. Collect the following data from the computational load entity:¹³
 - a. **Electrical Size and Power Factor** – Expected MW for minimum and maximum consumption as well as expected power factor, on a seasonal basis. If the computational load facility is expected to grow, include forecasted values of the buildout schedule for future-year studies.

⁸ See [NERC Rules of Procedure](#).

⁹ Section 810(5) of the ROP.

¹⁰ Some computational load entities seek to interconnect at pre-existing generation sites. TOs should reflect their appropriate interconnection requirements for computational loads for instances where these are directly connecting to the BPS as well as through a Generator Owner's Facility.

¹¹ More information on the PERC1 model can be found here: [Load Characteristic Model: PERC1](#)

¹² For more modeling information beyond this action, see NERC's [Dynamic Modeling Recommendations](#). The *PERC1* model covers a significant portion of the expected positive sequence behaviors expected from computational loads. A baseline set of requirements means that any successor model, more detailed model (e.g., EMT), or additional TP or PC specific requirements can be added on top of the data or information necessary to populate the *PERC1* model.

¹³ Alternatively, the TP or PC can collect this through a different entity, potentially even a Registered Entity.

- b. **Dynamic Characteristics** – Collect the parameters for the dynamic representation of the computational and cooling loads response as well as controller or device actions¹⁴ expected to operate during simulated Disturbances.¹⁵ Collect information or model parameters that affect the dynamic performance of the load facility including uninterruptable power supply (UPS) settings and configurations.
- c. **Composition** – Percentage of IT load vs. non-IT load (e.g., cooling/motor load) at various loading levels.¹⁶ This percentage should be used to allocate the percentage of electronic load models (e.g., PERC1 modeled load) vs. traditional load models for this facility in simulation models.
- d. **Expected Ramp Rate** – Expected maximum ramp rate (MW/min) in down-ramp and up-ramp.
- e. **Protective Devices** – TPs and PCs should model the actions of protection and control devices within the facility by representing them at the point of common coupling with the computational load with standalone models or integrated into equipment models. These models should represent voltage and frequency parameters and relays that could isolate this load from the BPS or reduce the facility's demand. TPs and PCs should also collect the reconnecting voltage and timing for when the computational load facility would be expected to reconnect to the System. These protection models should also represent relevant relays or control hardware that could “trip” and restore the facility¹⁷ or switch to and from backup power.
- f. **On-Site Generation** – Information regarding on-site generation for when the facility is expected to transfer to on-site generation or utilize the on-site generation for Demand Response or other controlled interactions. Full generation representation should be pursued if the generation source (inclusive of Battery Energy Storage Systems) plans to be operated in parallel with the BPS.
- g. **Facility Use** – Information on what the facility will be used for (e.g., traditional compute and storage, AI training, inference, or cryptocurrency mining). This may include percentages for each use-case when the facility has multiple use-cases and may additionally

¹⁴ NERC Incident Review [Considering Simultaneous Voltage-Sensitive Load Reductions](#)

¹⁵ See definition of Disturbance in the [NERC Glossary of Terms Used in Reliability Standards](#). This can include representation of the computational load during power oscillations.

¹⁶ Sometimes referred to as the power utilization effectiveness (PUE). PUE calculates the expected ratio of the load composition supporting the IT load. When using PUE ratios, submitting entities are encouraged to also include the type of non-IT loads to ensure proper motor load representation of the load facility.

¹⁷ For example, a relay model that includes parameters for a 0.85 p.u. voltage for 30 seconds would “trip” the load model in simulation.

require a separate set of model information for 2.b to 2.f in these different end-uses.

3. Implement processes and procedures to require specific modeling information from computational load entities during interconnection and throughout the operational lifecycle of the data center, including model updates when a qualified change¹⁸ to the facility occurs.

Essential Action #2

TPs and PCs should study their system¹⁹ with additional considerations for computational loads that include at least the following:

1. Evaluate System Operating Limits or similar operating envelope limitations for additional load to connect to the area before voltage or frequency instability. This may include P-Q and P-V analysis, system strength screening, or transient domain limits.
2. Identify areas vulnerable to instabilities due to computational loads and develop appropriate mitigation measures in accordance with established planning criteria.
3. Identify credible Contingencies²⁰ where the aggregate loss or reduction (including customer-initiated load reductions) of computational loads are expected to cause planning criteria violations and update Contingency files accordingly.²¹ The amount of load loss involved with these Contingencies should also be communicated to BAs and Resource Planners (RP).

Essential Action #3

PCs should revise their definition of “qualified change”²² that triggers a review of local area protection, stability limits, and other reliability studies to account for computational load. This definition should include language to account for the following:

1. Growth of the computational load.
2. Changes to settings, parameters, or configuration of the computational load electrical supply equipment and end-use equipment.

¹⁸ See [FAC-001-4](#) and [FAC-002-4](#).

¹⁹ This can be done through TPL-001 assessments or other planning analysis.

²⁰ The definition of Contingency is available in the *NERC Glossary of Terms used in Reliability Standards* here: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

²¹ The Contingency definition (i.e., elements affected) should be updated for all planning studies where the Contingency is credible.

²² See [FAC-001-4](#) and [FAC-002-4](#).

3. Repurposing²³ of computational load for a significantly different application.

Essential Action #4

TOs should establish a commissioning process for computational loads. Some items in the commissioning process may need to be repeated when a significant change to the facility occurs. This process should include all items required for operational readiness, including the following:

1. Processes to evaluate the “as-built” load facility model, including processes to assess model quality and for performing model verification and model validation.
2. Processes to notify owners of affected nearby systems (e.g., generation facilities) of planned load commissioning tests, in instances where the nearby system uses the same or electrically close point of common coupling to the BPS.
3. Where possible, a full facility load and no-load test of the facility and tests of applicable electrical control modes²⁴ of operation. Additionally, if possible, at least a 10% change from nominal voltage (both a 10% increase and a 10% decrease from nominal) should be performed with individual phase currents.²⁵ The full load, no-load, and voltage change testing should be performed with the facility’s computational equipment installed and operational.²⁶
4. Processes to ensure that communication and testing coordination capabilities are coordinated between the TO, TOP, BA, and RC and the computational load customer.
5. Processes to coordinate a commissioning checklist before energization between the TO and the computational load customer to review and test the functional performance of the facility. This checklist should also be coordinated with the relevant RCs, TOPs, and BAs; furthermore, surrounding GOPs should also be coordinated with where generation facilities are identified as part of item 2. The checklist should include items for the following:
 - a. Switching

²³ For example, altering the computational load facility from a data warehouse or crypto mining facility to an AI training facility.

²⁴ For example, switching from an “eco” mode on the UPS to supplying through on-site Battery Energy Storage Systems. These tests should be unique to the planned operation of the constructed facility.

²⁵ One possible method for performing this test is to change the tap setting on the step-down transformer to adjust the voltage on the low side of the transformer.

²⁶ Alternate verification of this capability and testing can exist that may satisfy the reliability need of these tests. The TO should use engineering judgement on if these tests are feasible at the time of commissioning.

- b. Design Prints
 - c. Functionally test electrical supply ac/dc protection circuitry
 - d. Functionally test electrical supply protection system settings
 - e. Functionally test supervisory control and data acquisition (SCADA) points
 - f. Functionally test remedial action schemes (RAS) if there is generation behind the meter that is not allowed to export.
 - g. Functionally test electrical equipment including circuit breakers, transformers, and onsite generation (if operated in parallel with the BPS)
 - h. In-service load and protection coordination checks
6. Verification after energization that all parties have the same or consistent data needed for the following:
- a. SCADA systems
 - b. As-built diagrams, ratings, and information
 - c. One-lines identifying responsibilities of TO and computational loads.

Essential Action #5

TPs and PCs should study and implement corrective actions with TOs on the system side of the interconnection to ensure no non-consequential loss of firm load for computational load from normally cleared non-bus faults.^{27,28} Loss of firm load can also be Non-Consequential load loss but does not include customer-initiated load reductions.²⁹

1. TPs and PCs should acquire the necessary facility-level relaying and protection settings, files, or configurations from the computational load entities. TPs and PCs should use that information to evaluate the response of the computational loads' protection and control systems to normally cleared faults.
2. TOs should coordinate with computational load customers, where possible, on customer-side improvements to maximize the

²⁷ NERC Incident Review [Considering Simultaneous Voltage-Sensitive Load Reductions](#)

²⁸ See TPL-001 Table 1 – Steady State & Stability Performance Planning Events for the events for which non-consequential load loss should not occur. In very limited and rare instances, some normally cleared faults may interrupt firm electric service. Table 1 and the surrounding TPL-001 requirements explicitly detail the performance expectations. Available here: [TPL-001-5.1](#)

²⁹ Non-Consequential load loss is defined in the [NERC Glossary of Terms used in Reliability Standards](#). Non-Consequential load loss occurs when load is isolated from the BPS that is not part of removing the faulted equipment.

computational load facility-level “ride-through” performance up to equipment capability limitations to increase stability margins.

Essential Action #6

TOs should install and utilize dynamic fault recording devices to capture and share computational load facility electrical performance during system disturbances. This action could be accomplished through collaboration with the computational load owner to install, or grant access to existing, dynamic fault recording devices. TOs may coordinate with the RC to determine at which computational load facilities these devices should be installed. This should include digital disturbance recording and fault recording technology for continuous recording at lower resolution and trigger-based recording at higher resolution (e.g., digital fault recorders). TOs should supply the data from these devices³⁰ as required by TPs, PC, RCs, Regional Entities, or the Electric Reliability Organization (ERO) to aid in event analysis and root-cause analysis for System Disturbances.

Essential Action #7

TOPs, RCs, and BAs should establish Interpersonal Communication³¹ capabilities with computational loads to improve their situational awareness and joint operating procedures to ensure the reliable operation of the BPS during planned and emergency conditions. TOPs, RCs, and BAs should issue instructions, orders, or similar information to computational load entities through voice, SCADA, or other communication platforms to prevent BES Emergencies.³²

³⁰ These specifications on sample rate, recording retention window, and specific triggers will be custom to the facility. Some information can be found in [PRC-028](#) and [PRC-002](#). See the Additional Information section below for a Reliability Guideline that also includes information on how to specify.

³¹ See definition of this term in the [NERC Glossary of Terms used in Reliability Standards](#).

³² See Recommendation 1 and Recommendation 4 of NERC’s Level 2 Alert for recommendation for how computational load entities should respond to these instructions. That is, computational load entities should comply with the issued instruction or order.

Reporting Instructions:

Initial acknowledgement of receipt is required by **May 11, 2026**, Midnight Eastern via the NERC Alert System. Responses to the questions below are required to be submitted via the NERC Alert System by **August 3, 2026**, Midnight Eastern.

A valid response in the NERC Alert System consists of the following three steps by the submitting entity:

- Acknowledgement of the Alert
- Submission of Response
- Approval of Response

The NERC Alert System contains menu options for each of the above commands that are available to authorized individuals upon login. A response will not be considered valid until all three steps have been completed.

All registered entities belonging to the TP, PC, TO, BA, RC, and TOP functional groups are required to acknowledge receipt of this Alert and respond, as applicable.

All registered entities covered by this Essential Action are required to provide an approved response as defined above to the following questions:

Questions

All Entities answer the following Questions:

1. Select the option to describe the workload required to implement Essential Action 1:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 1 is not applicable to my entity's functional group(s)
2. Select the option to describe the workload required to implement Essential Action 2:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 2 is not applicable to my entity's functional group(s)

3. Select the option to describe the workload required to implement Essential Action 3:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 3 is not applicable to my entity's functional group(s)
4. Select the option to describe the workload required to implement Essential Action 4:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 4 is not applicable to my entity's functional group(s)
5. Select the option to describe the workload required to implement Essential Action 5:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 5 is not applicable to my entity's functional group(s)
6. Select the option to describe the workload required to implement Essential Action 6:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 6 is not applicable to my entity's functional group(s)
7. Select the option to describe the workload required to implement Essential Action 7:
 - A. Low effort to implement changes
 - B. Significant effort to implement changes
 - C. Cumbersome workload and effort to implement changes
 - D. Essential Action 7 is not applicable to my entity's functional group(s)
8. Select the option to describe the level of external action required to implement the Essential Actions:

- A. Requires coordination with an external commercial entity
- B. Requires action by an external regulatory agency
- C. Requires no external coordination to implement

9. Please include additional information that provides better understanding for your responses in the text field.

TP and PC only

10. Do your current modeling requirements include the actions in Essential Action 1?

- A. Yes
- B. No, however, we plan to modify our requirements to include
- C. No, and we have no plans to modify our requirements

11. If you answered “No, however, we plan to modify our requirements to include” when do you plan to implement changes to your modeling requirements to align with Essential Action 1?

- A. 2026
- B. 2027
- C. 2028
- D. Beyond 2028

12. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.

13. Does your existing annual study process include the actions in Essential Action 2?

- A. Yes
- B. No, however, we plan to modify our requirements to include
- C. No, and we have no plans to modify our requirements

14. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 2?

- A. 2026
- B. 2027
- C. 2028
- D. Beyond 2028

15. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.
16. Do your current studies evaluate and provide mitigations for the items discussed in Essential Action 5?
- A. Yes
 - B. No, however, we plan to modify our requirements to include
 - C. No, and we have no plans to modify our requirements
17. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 5?
- A. 2026
 - B. 2027
 - C. 2028
 - D. Beyond 2028
18. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.

PC only

19. Does your definition of “qualified change” include the items discussed in Essential Action 3?
- A. Yes
 - B. No, however, we plan to modify our requirements to include
 - C. No, and we have no plans to modify our requirements
20. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 3?
- A. 2026
 - B. 2027
 - C. 2028
 - D. Beyond 2028
21. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.

TO Only

22. Do your existing commissioning practices include the items discussed in Essential Action 4?
- A. Yes
 - B. No, however, we plan to modify our requirements to include
 - C. No, and we have no plans to modify our requirements
23. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 4?
- A. 2026
 - B. 2027
 - C. 2028
 - D. Beyond 2028
24. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.
25. Do your existing protection and coordination practices include the items discussed in Essential Action 5?
- A. Yes
 - B. No, however, we plan to modify our requirements to include
 - C. No, and we have no plans to modify our requirements
26. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 5?
- A. 2026
 - B. 2027
 - C. 2028
 - D. Beyond 2028
27. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.
28. Do your existing dynamic fault recording devices or access to such devices include the items discussed in Essential Action 6?
- A. Yes
 - B. No, however, we plan to modify our requirements to include

C. No, and we have no plans to modify our requirements

29. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 6?

A. 2026

B. 2027

C. 2028

D. Beyond 2028

30. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.

TOPs, RCs, BAs Only

31. Do your current operating practices include the Interpersonal Communication practices discussed in Essential Action 7?

A. Yes

B. No, however, we plan to modify our requirements to include

C. No, and we have no plans to modify our requirements

32. If you answered “No, however, we plan to modify our requirements to include,” when do you plan to implement changes to your modeling requirements to align with Essential Action 7?

A. 2026

B. 2027

C. 2028

D. Beyond 2028

33. If you answered “No, and we have no plans to modify our requirements,” please explain in the text field.

Additional Information:

The rapid increase of computational loads continues to evolve. NERC has identified other risks, gaps, and materials that would be useful for recipients of this alert to follow. The following links provide additional information and best practices:

- [Large Load Action Plan](#) – Outlines NERC’s plan for further actions associated with computational loads, which also contains information about the draft registry criteria and standards project referenced in the alert.
- [Characteristics and Risks of Emerging Large Loads](#) – Highlights the risks and characteristics with large loads, including computational loads.
- [Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads](#) – Highlights the gaps in utility practices, NERC Reliability Standards, and other industry work related to large loads, including computational loads.
- [Reliability Guideline: Risk Mitigation for Emerging Large Loads](#) – Highlights the best practices to enhance entity practices to resolve gaps for large loads, including computational loads.
- [Data Center Information Collection Questionnaire](#) – Helps TPs model data centers using key information gathered from large loads for the purposes of data center modeling in transmission studies.

Contact:

For clarification or content-related questions, contact:

Engineering@nerc.net

For login/account/registration issues, contact:

nerc.alert@nerc.net

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North American Electric Reliability Corporation
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EXHIBIT J

Final

Risk Mitigation for Emerging Large Loads

Large Loads Working Group Reliability Guideline

May 2026

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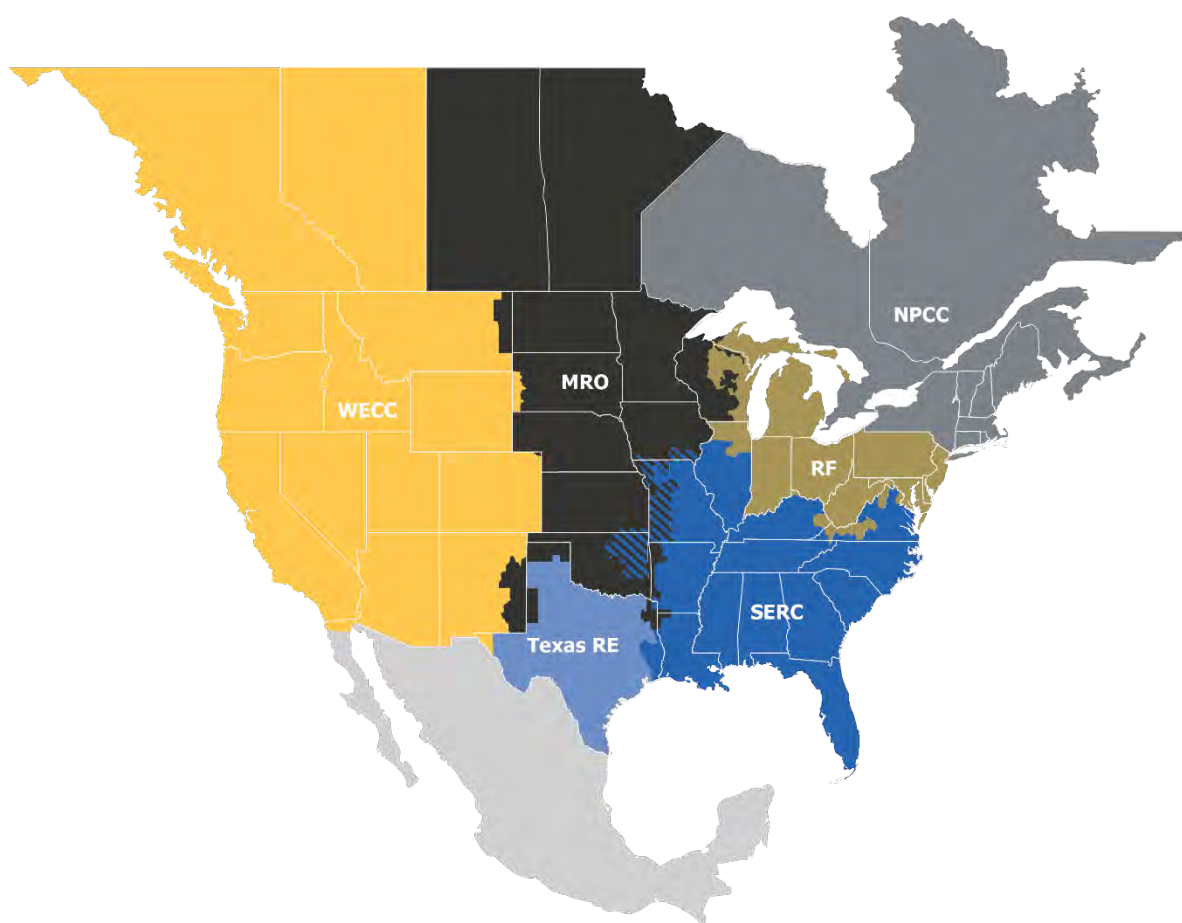
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY **POWERING TODAY. PROTECTING TOMORROW.**

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices

Executive Summary

Emerging Grid Challenges

Recent developments in emerging large loads and their integration into the BPS have introduced new BPS reliability risks. Some of these risks, like customer-initiated load reduction (CILR) events and large load oscillation events, have been clearly demonstrated and observed. These events can transpire in a matter of seconds, leaving real-time operators little to no time to respond. Additionally, planners anticipate long-term

These events can transpire in a matter of seconds, leaving real-time operators little or no time to respond.

risks related to transmission planning and resource adequacy. While these risks are not yet fully realized, they require proactive planning to mitigate. This reliability guideline details specific risk mitigations recommended for applicable entities to address the risks outlined in prior Large Load Working Group (LLWG) white papers.

Ensuring Consistent and Reliable Operations for All Users

This preliminary reliability guideline provides actionable BPS reliability-enhancing guidance for existing NERC registered entities as well as large load entities and their original equipment manufacturers (OEM).

Reliable integration of emerging large loads is not only essential for protecting the BPS but also to accommodate additional large loads faster. When interconnection and operational processes are structured to ensure reliability from the outset, emerging large loads can connect faster and in greater magnitude.

Reliable integration of emerging large loads enables the system to accommodate additional large loads faster.

Guidelines as a Supplement and Bridge to Standards

Although the guidance is voluntary and non-binding, NERC recommends that applicable entities implement the crucial risk mitigating actions and processes offered in this paper. NERC is updating its registry criteria and Reliability Standards to account for the needs associated with large loads, and these guidelines provide key information while the regulatory process moves forward. Implementing these guidelines can lead to enhanced system resilience, reduced outage risks, and more efficient interconnection processes. This guideline will also present future revisions to Reliability Standards. Thus, the guidance in this paper is intended to supplement, rather than replace, any existing or new Reliability Standards. Reliability guidelines are reviewed and updated at least every three years in accordance with the RSTC Charter and may be updated earlier in response to comments or lessons learned.

From Passive Consumption to Active Participation

This guideline recognizes that owners and operators of end-use facilities and equipment were not historically required to be as active in practices and processes that ensure BPS reliability. However, due to the scale and urgency of the risks to BPS reliability, it is strongly recommended that large load entity users of the BPS (if they are not already doing so) participate actively in practices and processes that enhance BPS reliability. Finally, large load entities are encouraged to participate in NERC task forces, webinars, comment periods, and the NERC Standards process to contribute their unique perspectives. The LLWG values the participation of large load entities in its task force and the resulting wholistic work products. Recommended risk mitigations are targeted at existing NERC registered entities as well as large load entities. Large load entities may include large load facility owners and operators. This guidance also extends to OEMs that create equipment used in large load facilities, such as IT equipment, IT cooling infrastructure, and other electronic devices. High-level recommendations with mapping to recommended entities are provided in [Appendix A](#).

Introduction

Purpose

This reliability guideline shares initial recommended practices, technical insights, and lessons learned for maintaining BPS reliability while integrating emerging large loads. This guideline will suggest mitigations for risks discussed in the prior LLWG white papers.

Applicability

This reliability guideline is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Resource Planners (RP)
- Large load entities (developers, owners, operators)
- Original Equipment Manufacturers (OEM) for large load facility equipment
- Generator Owners (GO)
- Generator Operators (GOP)
- Reliability and Security Technical Committee (RSTC) subgroups

Background

The first NERC LLWG work item, *White Paper: Characteristics and Risks of Emerging Large Loads*, defines large loads—including data centers, cryptocurrency mining facilities, hydrogen production facilities, manufacturing facilities, and arc furnaces—as “[a]ny commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors.” The paper identified key risks from emerging large loads along with the characteristics that can cause those risks. The standards project initiated on March 18, 2026, also includes consideration of the term computational load and computational load entities, which will help further refine this understanding.

The second pending NERC LLWG work item, *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, explains where there are gaps in addressing risks from emerging large loads in existing practices and Reliability Standards. The paper also categorizes risks based on impact and likelihood to recommend actions for mitigation, including Reliability Standards, NERC alerts, and reliability guidelines.

This reliability guideline addresses the second white paper’s recommendation to mitigate certain risks with a reliability guideline. This preliminary guideline moves beyond identification of risks and gaps to provide actionable, entity-specific recommendations even as revisions to NERC Rules of Procedure registry criteria

and Reliability Standards are underway. It should be read as both a supplement to and a bridge between the white papers and potential future Reliability Standards. Reliability guidelines are just one form of mitigation employed by NERC's Framework to Address Known and Emerging Reliability and Security Risks. Reliability guidelines are "the common approach to use when addressing moderate impact sustained risks that are unlikely, and low impact sustained risks that are unlikely or likely."¹ Reliability guidelines may also be used "to establish performance expectations for emerging risks prior to codifying those expectations into Reliability Standards." This reliability guideline will be used for both purposes: tackling the high-impact high-likelihood risks identified in the LLWG's prior white paper while also addressing moderate- and low-impact risks.

Vocabulary Terms

The reader of this reliability guideline should note that all terms contained in the NERC *Glossary of Terms*² and used in this guideline are capitalized. In addition to those terms, some additional terms are defined below. The definitions provided in this paper shall not supersede any future definitions created for the NERC *Glossary of Terms*. Those additional terms in italics are distinguished from those defined and approved by NERC.

NERC Glossary-Defined Terms

Area Control Error (ACE): The instantaneous difference between an entity's Actual Net Interchange (NIA) and Scheduled Net Interchange (NIS), taking into account the effects of Frequency Bias, of correction for meter error, and of Inadvertent Interchange Management (IIM) if operating in the IIM mode. For compliance usage, refer to the term Reporting ACE.

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Area's Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

BES Cyber System Information (BCSI): Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BCSI may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

Energy Reliability Assessment (ERA): Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Model Validation: The process of comparing simulation results with measurements to assess how closely a model's behavior matches the measured behavior.

¹ NERC, *Framework to Address Known and Emerging Reliability and Security Risks*, February 2021.

https://www.nerc.com/globalassets/who-we-are/standing-committees/risc/framework-address-known-emerging-reliability-security-risks_erratta_v1.pdf

² NERC, *Glossary of Terms Used in NERC Reliability Standards*, February 2026.

https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms.pdf

Model Verification: The process of confirming that model structure and parameter values represent the equipment or facility design and settings by reviewing equipment or facility design and settings documentation.

Operating Plan: A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan

Registered Entity: Entities required by law to register with NERC and comply with NERC Reliability Standards.

Terms Defined for This Paper

Many crucial terms used in this paper are not defined formally in the NERC *Glossary of Terms*, but that does not indicate that they necessarily should be added to the glossary. These terms are defined here to help readers in understanding the recommendations offered.

As-Built: The materials, settings, equipment, parameters, and layout of a facility as it was constructed and installed, including any deviations from the original design. This includes all post-commissioning modifications and always represents the current operational state.

As-Designed: The planned parameters and layout of a facility, based on preliminary engineering design prior to construction or installation.

Behind-the-Meter Generation: Generation resources that are connected to the BPS through the same point of interconnection as a load.

Buildout Schedule: The forecasted installed capacity of a large load facility on a monthly, quarterly, or yearly basis.

Cryptocurrency Mining: The process of using IT equipment (e.g., computers, application-specific integrated circuits) to solve mathematical problems to validate and enable various transactions.

Data Center: A physical room, building, or facility that houses IT infrastructure for building, running, and delivering applications and services.

Electrolyzer: A device that uses electricity to split water into hydrogen and oxygen.³

Electromagnetic Transient: A power systems domain that considers time-domain instantaneous values rather than phasor domain positive-sequence values for highly detailed analysis.

Large Load: Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces.

Large Load Entity: Any entity that owns, designs, or operates large load facilities.

³ U.S. Department of Energy, *Hydrogen Production: Electrolysis*, 2024. <https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis>

Large Load Operator: An entity that operates a large load facility.

Large Load Owner: An entity that owns or maintains a large load facility.

Phasor Measurement Unit: A time-synchronized measurement device that estimates the magnitude and phase of an electrical phasor quantity like voltage or current.

Point of Interconnection: The location of electrical connection between one system and another (i.e., from a generator or load to the transmission system).

Price Responsive: Behavior of a load facility where demand is dependent, in part or in whole, on energy prices.

Ramp Rate: The rate that a generator or load changes its output or Demand.⁴ The units used to describe ramp rate are typically in MW per second or MW per minute.

Site control: The legal authority or permission to occupy, develop, or use a specific parcel of land or property.⁵

Other Terms

This section is used to describe some additional terms in depth. Simply providing definitions for each of the following terms was deemed insufficient.

Co-Location and Colocation

Co-location and colocation are often pronounced the same, but the hyphen generally distinguishes the two terms between a term commonly used in the data center industry and a term commonly used in the utility industry.

Co-location in the utility industry generally refers to two or more facilities sited close to one another. In some circumstances, co-location refers to two or more facilities behind the same point of interconnection.⁶ In other circumstances, co-location may refer to many facilities sited in the same general geographic area.

Colocation (also referred to as “colo”) in the data center industry refers to “the placement of an organization’s own servers and other essential computing hardware for data storage in rented space within a physical data center owned and/or operated by a third party.”⁷ Colocation may come with increased challenges for the data center owner and operator in predicting demand or other behavior of the end-use equipment.

Customer-Initiated Load Reduction and Load Loss

Historically, load loss has been used to communicate the loss of service to customer load due to an outage in distribution or transmission facilities.⁸ The distinction between load loss and customer-initiated load

⁴ Ramp Rate is defined in the NERC *Glossary of Terms*, but it excludes mention of demand changes.

⁵ Cobrief, *Site control: Overview, definition, and example*, Cobrief.app, March 2025. <https://www.cobrief.app/resources/legal-glossary/site-control-overview-definition-and-example/>

⁶ NERC, *Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants*, June 2023. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/irps/reliability_guideline_bess_hybrid_performance_modeling_studies.pdf

⁷ Equinix, *What is Colocation?*, June 2023. <https://www.equinix.com/what-is-colocation>

⁸ NERC, *Possible Misunderstandings of the Term ‘Load Loss’*, March 2021. https://www.nerc.com/globalassets/our-work/reports/white-papers/white_paper_load_loss.pdf

reduction (CILR) is described mainly with regard to residential air conditioners shutting down due to the action taken by controls in each air conditioner that cause the air conditioner to shut down and then restart 10–20 minutes later. In those situations, the air conditioner using control actions to shut down is a CILR. It is also known that adjustable speed drives used in many industrial processes, as well as chillers and air handlers for large commercial buildings, will typically respond to a transmission system fault by shutting down. This occurs even though the fault is very remote from the customer’s location and does not cause a loss of service to the customer. Depending on the control system, such as an energy management system used in an industrial facility or commercial property, the equipment may restart automatically after a time delay or may restart only after a human operator takes action. Large customers may switch over to a standby power source automatically even if faults on the BPS are very remote and do not result in an actual loss of service to the facility. Many such facilities perform the automatic switch to BPS-level faults. Customer-owned controls that react to a fault or disturbance on the BPS may prompt a significant amount of CILR; however, these customers do not experience an actual loss of service, and this is not considered a “load loss” in the historical use of the term.

Load loss is formally defined with two terms in the NERC *Glossary of Terms*: Consequential Load Loss and Non-Consequential Load Loss. Both definitions explicitly exclude CILR caused by voltage-sensitive load.

There are multiple causes of CILR, especially for large loads. The first and best-documented cause is voltage-sensitive load that senses a low voltage condition and automatically takes a control or protection action that results in the reduction of demand.^{9,10,11,12}

A newly identified driver of CILR involves distributed computing workloads shared across geographically or electrically disparate data centers. When a transmission fault causes a low-voltage condition at a single facility, the interruption of the shared process triggers a synchronized demand reduction across all participating data centers, including those completely unaffected by the fault and low voltage condition. This cause of CILR is not well documented.

⁹ NERC, *Incident Review Considering Simultaneous Voltage-Sensitive Load Reductions*, January 2025.

https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf

¹⁰ NERC, *Incident Review Voltage-Sensitive Crypto Load Reductions*, January 2026. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf

¹¹ EirGrid and SONI, *Large Demand Facility Fault Ride-Through Issue and Proposed Solutions*, November 2025.

<https://cms.eirgrid.ie/mpid345-large-demand-facility-fault-ride-through-issue-and-proposed-solutions-eirgrid-and-soni>

¹² R. Rabbani, *Large Demand Technical Requirements*, presented at the Grid Code Development Forum, November 2025, pp. 8–21.

<https://www.neso.energy/calendar/grid-code-development-forum-gcdf-5-november-2025>

Chapter 1: Data Collection and Modeling

Data collection is foundational to ensuring reliable integration of large loads into the BPS. This chapter offers many recommended risk mitigations related to data collection, verification, and validation. Additionally, this chapter aims to specify beneficial data collection and sharing activities and processes that will support planning and operational mitigations to effectively and efficiently mitigate risks to BPS reliability.

Collecting data about load facilities helps grid planners and operators make informed decisions about planning and operating the BPS in a way that ensures reliability. Without the proper data to simulate and characterize large loads, grid planners and operators will be unable to accurately model large loads, leading to inaccurate analysis of BPS reliability and uninformed decisions when planning and operating the grid. This means that grid planners and operators need to specify the type, format, and frequency of data submissions required from large load entities across the interconnection, planning, and operations domains.

The second critical component to ensure reliability and mitigate risks after collecting the data to simulate large loads is to share the data with relevant entities. Once the interconnecting entity (i.e., TO or DP) collects data about the end-use facility, it has a duty to share that data with the appropriate entities (e.g., TP, PC, RC, BA, and TOPs) that rely on that data to ensure reliability. This information sharing and coordination activity should be performed as soon as the data is available to share, or as otherwise required by the TPs, PCs, RCs, RPs, BAs, and TOPs. This may include sharing information with neighboring entities to ensure reliability in both systems. Many NERC Reliability Standards already exist for this exact purpose.^{13,14,15}

Data Collection Stages

Load interconnection processes and stages often vary from entity to entity. This reliability guideline will break down data collection into three main stages, as shown in **Figure 1.1**, interconnection evaluation, integration and commissioning, and operations. TOs, in coordination with their TPs and PCs, should create timelines associated with data submission requirements that enable studies.

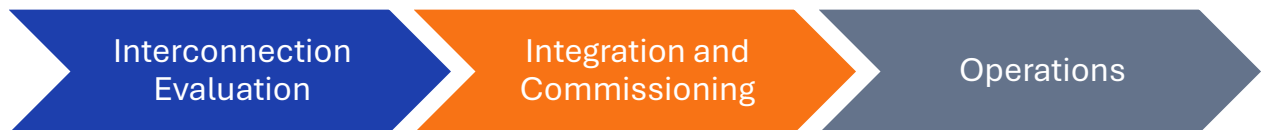


Figure 1.1: Data Collection and Modeling Throughout the Project Lifecycle

The interconnection evaluation stages spans from when the TO or DP first receives the request to interconnect to its facilities until the interconnection agreement is signed. During the interconnection evaluation stages, the load facility may only have a partially complete design. This means initial data submissions are expected to be updated throughout subsequent stages.

The integration and commissioning stage generally starts when the interconnection agreement is signed and ends when the load facility is first energized with grid interconnection. During this stage, the load facility finalizes its design, constructs the load facility, and completes commissioning activities in collaboration with the utility.

The operations stage starts when the load facility when the load facility is first energized with grid interconnection and ends when the facility is fully retired. During operations, TOPs, BAs, and RCs should

¹³ [FAC-002-4](#)

¹⁴ [IRO-010-5](#)

¹⁵ [TOP-003-7 and BAL-007-1](#)

receive key operational data on an ongoing basis from large load entities. Additionally, large load entities should provide updated as-built models and data to their TOs, TP, and PC following any site modifications, upgrades, or other qualifying changes.

When a large load seeks to connect to the grid, utilities are required to perform a full reliability study per FAC-002 and other relevant assessments, including resource and transmission adequacy assessments. These studies are performed to identify any potential impacts to the transmission system along with any network upgrades that may be required to reliably integrate these large loads into the BPS. Due to the complexity and time required to perform these studies, many utilities may have their own process to conduct the steady-state and transient stability evaluation at various stages of the interconnection process shown in **Figure 1.1**.

Large load entities, TOs, and DPs should collaborate with TP and PC through the TO's or DP's interconnection requirements per FAC-001 and MOD-032 to provide all the necessary information required during various stages of the interconnection process. This data should be collected as early as possible with the understanding that the collected data and models may need to be updated throughout the large load facility's lifecycle. This collaboration will ensure the provision of site-specific data necessary for developing accurate models for steady-state and dynamic studies as part of the interconnection requirements. Due to the risk of inaccurate or incomplete data submission, some utilities may require large load entities to prepare and submit the models and supporting documentation for review. Alternatively, other utilities may develop the models themselves by using the information provided by the large load entity. Both approaches have inherent risks: customer-submitted models may lack transparency or independent validation, while utility-developed models could miss critical details if customer data is incomplete. Standardized procedures for model verification, model validation, and attestation of large load data/models are recommended to close this gap.

Utilities should incorporate provisions for ability to gather new information as large load-specific data requirements may evolve. Additionally, large load entities should anticipate evolving data collection requirements throughout the project lifecycle.

Interconnection Evaluation Stage

During the evaluation stage, the large load typically only has access to preliminary design plans and does not complete any construction. This preliminary design data (shown in subsections below) will form the basis of BPS reliability assessments by the interconnecting entity (TO or DP) until design plans are finalized in the next stage and the assessments can be refined with data based on actual procured equipment parameters.

TOs, in coordination with TP and PC, should create interconnection request requirements that establish a minimum set of data that must be submitted prior to evaluating interconnection of a large load facility. This minimum data requirement should allow for the large loads to be fully and properly studied per FAC-002. These studies are explained further throughout the rest of the reliability guideline. For any information not available upon initial study, updated information should be provided as it becomes available.

TOs, TP, and PC should coordinate and collect the following recommended data for the interconnection study process. In addition, the large load entity that will own and operate the equipment should provide this data to the TOs, TP, and PC.

Steady-State Modeling

Steady-state modeling data forms the foundation for transmission planning and interconnection studies. MOD-032 requires some existing registered entities to provide steady-state data to their TP and PC according to requirements and reporting procedures developed by the TP and PC.

Large load entities should coordinate with their TOs, TPs, and PCs to provide the following data:

- Requested peak net real power demand, on-site generation plan, and facility expansion plans
 - This includes load facility buildout schedule (MW energized on a monthly/yearly basis)
- Overall large load power factor (value and lead/lag) information for various loading (% rated load) levels
 - The data collection should clearly state where the power factor is specified (medium voltage, high-voltage, point-of-interconnection, etc.)
- Preliminary detailed one-line diagram of all large load equipment (and substation if any) showing network topology, breaker configurations, schematics of their switching arrangements (especially for facilities fed by multiple utility feeders), on-site generators, or battery energy storage system (BESS)
- Reactive devices (STATCOM, switched shunt, etc.) and their associated details (size, number of steps, connected voltage level, etc.)

Dynamic Modeling

Accurate dynamic modeling of large load facilities is crucial to assessing risk. MOD-032 requires some existing registered entities to provide dynamics data to their TPs and PCs according to requirements and reporting procedures developed by the TP and PC. NERC offers some resources to entities to help with accurate dynamic modeling. One such resource is the Load Modeling Working Group (LMWG) Data Center Information Collection Questionnaire, which “help[s] transmission planners identify reliability challenges in the power system and then devise mitigation measures to address them.”¹⁶ Additionally, NERC maintains a dynamic modeling guideline to provide clear and more comprehensive recommendations regarding the use of dynamic models for different types of reliability studies.¹⁷ Large load entities should develop and maintain site-specific dynamic models of their facilities. During design and construction of large load facilities, models are considered “as-designed.” Large load entities should update their as-designed models to as-built models after construction and any other subsequent qualified change (as defined by the TP and PC) to the facility.

Site-specific as-designed positive-sequence phasor domain (PSPD) dynamic large load models should include considerations for all of the following elements:

- Protection and Control
 - Disclosure of all protection devices and equipment settings
 - OEM test reports (as soon as they are available or updated) that include information necessary for model verification
 - Disconnection and real-power reduction thresholds for voltage and frequency events (levels and duration) at which the components within the large load will disconnect from the utility system or transfer to backup system
 - Reconnection threshold (levels and duration) at which the components within the large load (e.g., IT load, cooling load) will reconnect to the utility system and real-power ramp rates

¹⁶ NERC, *Data Center Information Collection Questionnaire*, 2024. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/lmwg/data-center-information-collection-questionnaire.pdf>

¹⁷ NERC, *Dynamic Modeling Recommendations*, 2024. <https://www.nerc.com/globalassets/programs/rapa/dynamic-modeling-recommendations.pdf>

- As-designed breakdown of load makeup, including IT equipment, motor load, variable frequency drive (VFD), power electronics, and lighting, including attestation of model parameters that map to load makeup
- Device dynamics
 - Constant voltage, current, or power behavior
 - Active power electronics
 - Reactive devices (STATCOM, switched shunt, etc.)
 - Any hardware or software solutions in the load end to smooth out oscillations

In addition to the site-specific as-designed phasor domain dynamic load models, large load entities should coordinate directly with their OEM to develop and maintain a site-specific as-designed electromagnetic transient (EMT) domain model of their facility. The model may be required by TP and/or PC.

Other Load Data

For adequate risk mitigation, it is recommended that large load entities provide the following data to relevant entities as requested by their TO, TOP, BA, RC, TP, PC, and RP:

- Ramp rate expectations
 - Maximum and minimum ramp rates (startup and shutdown)
 - Any cyclical demand ramps and their associated frequencies (especially in the sub-synchronous frequency range)
- To the best extent feasible, expected sub-hourly demand profiles should be collected
- Disclosure of large load facility demand being connected with other large load facilities connecting through alternate POIs (example: multiple disparate data centers used for the same training process where an interruption at one data center causes demand changes for all the connected data centers)
- Load make up/usage information, such as portion of AI training load in data center loads
 - Multi-tenant data center businesses (or other data centers with multiple types of workloads) should include the worst-case variability of all tenants combined.
 - Changes to this information are crucial to supply to the utility and may affect grid reliability.
- Harmonics
 - Expected current and voltage harmonic injection spectrum from the facility and aggregated at point of connection (details noted in [Chapter 6](#))
- Other
 - Backup generators or BESS not disclosed through the regular generator interconnection process
 - A description of the use cases of the on-site generator or BESS
 - How long can the load operate disconnected from the utility with the on-site resource
 - Type of large load (computational, industrial, etc.) or data center and its expected operations (e.g., AI training, cryptocurrency mining, traditional cloud, electric arc furnaces, oil and gas load facilities)

Integration and Commissioning Stage

During the integration stage, the large load entity finalizes the load facility design and performs construction. During this stage, the large load entity should be providing verified as-built data to the interconnecting entity (TO or DP). In turn, the TO should share the data updates with TPs, PCs, and other relevant entities. Sharing the latest updated data is especially important for data like dynamic models.

TOs, TPs, PCs, TOPs, BAs, and RCs should coordinate and collect the data recommended in the following subsections during the integration and commissioning stage.

Updates to Modeling Data

As mentioned previously, steady-state, dynamics, and short-circuit modeling data forms the foundation for transmission planning and interconnection studies. MOD-032 requires some existing registered entities to provide this data to their TPs and PCs according to requirements and reporting procedures developed by the TP and PC. It is recommended that large load entities update their modeling data and provide those updates to their TO, TP, and PC throughout the construction and finalization of the large load facility. When the facility is finalized and nearing commissioning, the large load entity should update its models to as-built models.

Additionally, at this stage, large load entities should perform model verification. More details on model verification processes are given at the end of the chapter.

Monitoring Equipment

To facilitate the reliable operation of the BPS, large load facilities need high-speed monitoring devices installed at the high side of the main power transformer. Crucial high-speed recording devices should be capable of measuring triggered fault recording (FR), continuous dynamic disturbance recording (DDR), and sequence of events recording (SER) data. FR and DDR recording data should be measured, at least, at the high-side main power transformer and should meet specifications for sampling rate, recording window, and triggers, similar to those in PRC-002 and PRC-028.^{18,19} The SER recording device(s) should also meet specifications similar to those in PRC-002 and PRC-028. The requirements for offline data storage capabilities and retention should be determined by the TP and PC.

The combined detection capabilities of the FR and DDR devices should be adequate for the following uses:

- Dynamic model validation (see end of this chapter) and performance evaluation
- Event analysis (see [Chapter 4](#))
- Oscillation detection and analysis (see [Chapter 5](#))

Additionally, TOs should ensure that sufficient power quality monitoring is installed prior to commissioning. More details are provided in [Chapter 6](#).

Other Load Data

All data mentioned in the prior “Other Load Data” section should be updated up to and after commissioning. Changes to this information are crucial to supply to the utility and may affect grid reliability.

¹⁸ [PRC-002-5](#)

¹⁹ [PRC-028-1](#)

Operations Stage

The operations stage is defined by ongoing coordination and data sharing between the large load entity, TO, TOP, TP, PC, BA, and RC. This stage is broken into two main categories: ongoing data sharing (e.g., telemetry of equipment statuses and measured values, disturbance monitoring and reporting) and data updates (e.g., new dynamic model, additional load). Per FAC-002, qualified changes to the large load facility must be studied. In addition, FAC-002 states that PCs must maintain a publicly available definition of qualified change. It is strongly recommended that PCs include any changes to demand over a determined threshold or dynamic model performance in their definition of qualified change. Updating data that was provided in prior stages is crucial to ensuring ongoing reliable operations of the BPS. However, the operations stage involves ongoing event- and time-based data collection, coordination activities, and real-time monitoring. Together, these activities support reliable operation and planning of the BPS.

Large load entities should provide and TOs and DPs should collect and share with relevant entities (TOP, TP, PC, BA, RC, and other entities responsible for forecasting, dispatching, and real-time operations) at least the following:

- Data Updates
 - Any updates for as-built facility information, including all prior mentioned steady state, dynamics, and short circuit data
 - All necessary information (defined by the BA, TOPs, and RCs) to conduct real-time analyses and assessments (TOP-003 and IRO-010) to address the potential risks due to large load ramping, disconnection, and reconnection to the grid
 - Expected load profiles, equipment specifications, ramp rates, load forecasts, real-time telemetry, event data, and logs following grid disturbances, backup generation, and demand response
 - Updated models whenever qualified changes are made to the facility
- Ongoing Data Sharing
 - Coordinate with the TO, TOP, BA, and RC to provide real-time measurements of key electrical quantities (real power, reactive power, and voltage) of each large load facility (if not already monitored by TO)
 - Near-Term Data Sharing
 - Day-ahead operating plan and indicative plan for near-term demand (7–10 days)²⁰
 - Outage scheduling information
- Post-Event Data Sharing
 - Share all required event data with relevant entities (mentioned above and in [Chapter 4](#)) upon request within a time period determined by the TP and PC (example: 90 days of request)

Dynamic Model Assessment, Verification, and Validation

Accurate dynamic models of large load facilities are required to understand reliability implications and potential mitigations. The inaccurate modeling of large loads can be mitigated by verifying the models and modeling information at various stages of the interconnection process, followed by validation processes during and after commissioning processes.

²⁰ While it is acknowledged that large load entities cannot always perfectly forecast demand, forecasts based on historical data and other operational data to which the large load entity has access will help mitigate risks from large load variability.

Large load entities, in coordination with the OEMs of the facility equipment, should create and maintain validated as-left models so that grid planners and operators can make informed decisions regarding BPS operations. Therefore, large load entities should supply (and TOs and DPs should require) accurate, verified, and updated data at various stages (e.g., as-designed, as-built, and as-left) of the planning, integration, and ongoing operations stages of the project lifecycle, including any material updates to equipment that would impact modeling or settings.

Each TO, in coordination with its TP and PC, should implement the following processes throughout their data collection processes:

- **Model Quality Assessment**
 - Model quality assessment that includes “evaluating the plausibility, usability, and numeric stability of a model based on a review of model documentation, data, and simulations”²¹
- **Model Verification Process**
 - Model verification requirements may include benchmarking PSPD models against EMT models of the facility.
 - Large load entities should maintain and share dynamic models that accurately represent the installed equipment and parameters, including performing model verification and providing the model verification report to relevant entities (TPs and PCs) prior to energizing.
 - Large load entities should provide attestation that the as-built model parameters represent the installed equipment rather than default parameters that don’t represent the specific facility.
- **Model Validation and Performance Analysis**
 - **Develop Event Data Collection Processes:**
 - Large load entities, in coordination with their TOs and DPs, should install high-resolution FR and DDR capable devices for large loads.
 - Recording devices should possess detection capabilities for at-risk oscillation frequencies with offline data storage capabilities and retention as determined by TP and PC.
 - **Establish Model Validation and Post-Event Analysis Process:**
 - TPs and PCs should develop a process for post-event data sharing and analysis, involving large load entities, TPs, TOPs, BAs, and RCs, to validate the large load’s performance and model accuracy based on the collected measurement data.
 - **Establish Process for Model Updates and Re-Study:**
 - TPs and PCs should establish a process for large load models to be updated given model validation and post-event analysis data.
 - TPs and PCs should also establish criteria for model updates and what qualified changes require a re-study.

²¹ IEEE, "IEEE Approved Draft Recommended Practice for Test and Verification Procedures for Inverter-based Resources Interconnecting with Bulk Power Systems," in IEEE P2800.2/D4.1, November 2025.
<https://ieeexplore.ieee.org/document/11261433>

Chapter 2: Interconnection Studies and Processes

TPs and PCs should establish a comprehensive interconnection process and periodic near-term system-wide study process using steady-state, dynamic, and short-circuit models to assess the reliability impacts of large loads. TPs and PCs should coordinate with TOs and DP in their areas to collect data needed for the interconnection process.

TOs, in coordination with TOPs, BA, TPs, PCs, and RCs, should establish and publish a comprehensive, consistent interconnection process that includes the following:

- A method for collecting, at a minimum, the data required in [Chapter 1](#)
- A definition of readiness criteria and an evaluation of any new interconnection application against the readiness criteria before continuing in the interconnection process
- Interconnection study agreement and associated process
- Interconnection studies using steady-state, dynamic (PSPD and EMT if needed), and short-circuit models to assess reliability impacts of large loads
- A periodic process in the near term that studies the collective impact of all large loads in a region defined by the PC that energize in a common time frame using steady-state and dynamic models
- A comprehensive commissioning process that ensures operational readiness for large loads, as detailed in [Chapter 4](#)
- Consideration of potential impacts to underfrequency load shed (UFLS) and undervoltage load shed (UVLS) plans, as detailed in [Chapter 8](#)

Interconnection Studies

TPs and PCs should incorporate at least the following in their large load interconnection study processes in order to ensure that the reliability impact is adequately studied:

- Steady-state studies based on the as-designed data provided by large loads to the TOs and updated as necessary, based on design, upgrades, or other qualifying changes
- Transient dynamic analyses that consider the following:
 - The large load facility on-fault and post-disturbance frequency and voltage recovery behavior
 - The collective impact of electrically close facilities
 - The total potential magnitude of load loss considering the individual and collective tripping or customer-initiated load reduction of large loads during system disturbances
- Transmission protection and control coordination studies that include the following:
 - Recommendations to TOs regarding any transmission protection coordination changes to transmission relays or modifications to large load fault interruption devices to ensure reliable isolation of system faults
 - Recommendation on changes to protection and control settings of local protective devices
 - Recommendations on changes to operation, protection, and control settings of the large loads to minimize customer-initiated load reduction during system disturbances
 - TOs, TOPs, and large load entities should coordinate and study any potential configurations with a risk of a customer's equipment impacting flows on the BPS (outside of when the large load is

served radially) so that power is not transported to another part of the system through the customer's equipment

- Inclusion of large load entity input into the TO coordination of protection and control devices to identify how the large load can assist in the reliable isolation of system faults
- TPs and PCs should create a process to determine when it is necessary to conduct small-signal, sub-synchronous, and transient stability assessments
- TPs and PCs should develop EMT screening criteria where needed²² (e.g., for sub-synchronous interaction); each of the following may be used as EMT screening criteria, subject to the discretion of the TP and PC:
 - When PSPD simulations do not converge or do not demonstrate the reliability concerns of interest
 - Large power electronic devices
 - Including HVdc lines, large electric arc furnaces, inverter-based resources (IBR), or static reactive power devices
 - Weak grid conditions
 - In the context of converter-driven stability, this may correspond to a short-circuit ratio of two or less,²³ as defined by the three-phase bus fault current available from the system and the total apparent power rating of the power electronics on site
 - Series capacitors
 - Large steam, gas, or hydroelectric turbine generators
 - These are of particular concern if the load profile has significant fluctuations in the five to 60 Hz range

Triggers for Re-Study

Similar to the existing Reliability Standard FAC-002, TPs and PCs should create and publish criteria that trigger a re-study of the large load facility. Experts in the ERCOT region state that some large load facilities have changed from a data center to a cryptocurrency mining facility after receiving approval of their interconnection request application. Late-stage modifications like this would almost certainly require a new dynamic study. This scenario is clear, but less-clear scenarios should also be examined in the PC's re-study criteria.

TOs and DPs should have clear policies for handling significant changes in load characteristics that occur after the initial interconnection studies. Large load facility characteristics may vary significantly with design decisions made during the interconnection process (e.g., the selection of specific vendors for electronic devices or determination of the site's mix of computational processes). These changes may introduce stability-related risks that were not identified in the initial studies as the result of the mismatch between prior and current load model data. This could necessitate technical mitigations (e.g., system upgrades or devices such as energy storage or reactive power support) that require significant cost and lead time to install. If these mitigations cannot be put in place by the original energization date, it may be necessary to delay energization or restrict the load's operational range until the mitigations are in place. For almost any

²² Screening criteria specific to large loads are not yet widely established. Traditional EMT screening criteria for oscillation-related reliability issues associated with power electronics may be considered.

²³ A short-circuit ratio of two or less is offered as an example, not as final guidance. Additionally, other types of short-circuit ratio may be more appropriate as screening criteria.

facility, some differences between as-designed and as-built models are inevitable, and these policies should provide reasonable accommodation for changes in load characteristics that do not significantly alter the reliability risks associated with the load interconnection. TOs, DPs, and load owners all face cost, schedule, and reliability risks when major changes to interconnection scope occur. Therefore, they should collaborate to identify and prioritize specific model data and design decisions that are most crucial for accurate BPS reliability assessments as early as possible.

Chapter 3: Long-Term Planning and Resource Adequacy

The incorporation of new large load interconnection requests into reliability assessments is not only vital to accurate studies of the BPS but also needed to ensure that future transmission design is adequately modeled. Inadequate modeling of large load interconnections poses risks to BPS planning by potentially leading to incorrect study results and incorrect long-term planning assumptions.

A primary risk to BPS reliability from large loads in the long-term planning and resource adequacy domains is insufficient transmission and generation caused by under-forecasting demand.

Regardless of whether large load studies are performed in a cluster or serially, TPs and PCs should coordinate with TOs to establish study processes to ensure that large load facilities interconnected to the BPS are adequately studied.

Analysis for Transmission Planning

The sudden and uncoordinated loss of a large load could cause overvoltage and overfrequency conditions that trigger protective relays that lead to a cascading outage, and the highly variable nature of some large loads' demand profile can induce risks outside of the traditional peak and off-peak scenarios studied in transmission planning analysis. Therefore, when conducting analysis for transmission planning studies, TPs should modify their study assumptions to capture the risks that large loads pose due to their size and operational behaviors.

To mitigate the risks posed by the sudden loss or rapid reduction of a large load, the loss of the large load should be studied as a contingency in both steady-state and dynamic assessments by the TP and PC. Similarly, the TP and PC should study credible loss of large loads clusters (all in close electrical proximity to a single fault or disturbance) and provide that information to the RP, BA, and TOP.

Planning processes should analyze various loading scenarios representing a diversity of load demand and generation patterns as appropriate for their areas in both steady-state and dynamic assessments. The dynamic assessment should include voltage stability and frequency stability assessments as documented in [Chapter 5](#).

Interregional Coordination Between Grid Planners

If a TP or PC studies and approves a project, such as an addition of a transmission line, that project can significantly impact the neighboring entities depending upon the size and location of the project. Therefore, TPs and PCs should coordinate with neighboring entities to account for such projects, whereby the models, the contingencies, and the study results are shared with the neighboring entities to help them perform their own studies.

Large loads interconnecting at the seam/boundary with a neighboring entity could have significant reliability impacts on that entity. Therefore, it is important for the RCs, TPs, and PCs to establish the processes for sharing pertinent information and data of the large load facility, such as load size, type, dynamic model data, and protection settings, with the neighboring entity at the interconnection stage. This allows the neighboring entity to perform its own studies whether independently or in collaboration with the incumbent entity. Moreover, there should be processes for the entities to share the results of reliability studies where any reliability issues are found at the neighboring entities' facilities. This would facilitate identifying system upgrades to mitigate such reliability issues.

Resource Adequacy Analysis

Given that large loads frequently seek connection to the grid faster than transmission and some forms of generation can be built and due to the size of these large loads, they can pose risks to resource adequacy as documented in the NERC LLWG *White Paper: Characteristics and Risks of Emerging Large Loads* section on Resource Adequacy.

Simulation of Delayed Generation Interconnections

Demand may outstrip generation supply as large loads are added faster than the addition of generation resources. Many large loads are expected to require firm service, limiting their ability to be considered flexible or providing limited demand-response capabilities. This directly impacts BPS reliability through the reduction of BA Operating Reserves. To address this, RPs should model scenarios in their evaluation of resource adequacy, such as delayed generation additions, before incorporating large load additions.

RPs should coordinate with load-serving entities, TOs, DP, and TP/PCs to identify the expected large load growth to incorporate in their studies, consistent with state, provincial, and federal regulatory requirements. The load growth may include a buildout schedule that occurs over the course of months to years. These buildout schedules should be considered in studies. An example would be a facility that increases the amount of load each month, quarter, or year as construction is completed. The modeling criteria may consider “tiers” of load additions, like the generator tier levels of the *Long-Term Reliability Assessment* (LTRA),²⁴ to demonstrate the quantity and timing of large load additions based upon confidence levels for those values. RPs can use this information to understand the level of risk associated with the timing of large load additions coupled with timing of generation additions.

Without the ability to model the timing and likelihood of new large load additions and new generation resources, RPs could miss key inputs to resource adequacy studies. These missed inputs could lead to inaccurate resource plans or the underestimation of the risks associated with those plans.

Simulate Operational Constraints and Flexibility of Large Loads

The risk to resource adequacy from the lack of representation of large loads’ operational flexibility and constraints is discussed in the NERC LLWG *White Paper: Characteristics and Risks of Emerging Large Loads*²⁵ and *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*. NERC’s *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*²⁶ (NERC Energy Reliability Assessment Working Group) echoes this by emphasizing the need for accurate modeling of demand response and non-conventional load behavior.

Large loads introduce complexities (operational constraints, partial controllability, or internal energy assets) that traditional resource adequacy models can fail to capture. Large load operating schedules, driven by an array of different processes, can limit load flexibility and controllability. Co-located generation and storage can make these loads appear firm where in reality, they may switch between grid supply and on-site resources, creating unpredictable net demand patterns. They can have rapid ramp rates (up or down), operational constraints, and behind-the-meter (BTM) generation or storage that traditional models do not capture. If operational characteristics are not represented in resource adequacy models and flexibility

²⁴ NERC, *Long-Term Reliability Assessment*, January 2026. https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf

²⁵ NERC, *White Paper: Characteristics and Risks of Emerging Large Loads*, July 2025. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf>

²⁶ NERC, *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*, December 2024. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/erawg/technical-reference-document-considerations-for-performing-an-era-v2.pdf>

assessment, planners may overestimate available flexibility or underestimate load variability—leading to misaligned resource procurement and reliability events during peak demand, large loads switching on and off, or large loads transferring to co-located and/or BTM generation.

While traditional RA frameworks typically assume static or predictable load profiles, failure to represent the constraints and operational characteristics of large loads (including interactions with BTM generation and/or storage) can lead to underestimating load variability or overestimating system flexibility, leading to misaligned resource procurement and increase in loss of load risk during peak demand periods, periods when large loads switch on and off, or those when large loads transfer from the grid to on-site co-located generation and vice-versa.

RPs should update their planning processes and resource adequacy models to include realistic assumptions about operational constraints and flexibility of large loads. They should follow NERC's ERA guidance to model demand-side variability, including time-coupled constraints and state-dependent behaviors. The updated models should be able to capture dispatch constraints (e.g., minimum runtimes, startup/shutdown behavior), separate firm vs. flexible load components, time-varying operating limits (e.g., AI training window), and characteristics of the BTM resources (e.g., solar power plants, BESS, backup gensets) and should consider whether it is appropriate to run sensitivity analysis under various scenarios (e.g., no load flexibility, partial or full demand response availability, fast ramping events).

Large load entities should provide documentation—as required and requested by the RPs—of expected dispatchability, ramp rates, internal generation/storage characteristics, technical constraints, and operating limits (e.g., IT workload cycles, min/max uptime). This mitigation ensures that load behavior is realistically modeled, preventing false assumptions about demand-side flexibility. Additionally, this mitigation improves the accuracy of load/resource balance forecasts, enhances planners' ability to predict and prepare for realistic worst-case conditions, and better aligns planning decisions with actual load behavior.

This mitigation enables planners to do the following:

- Accurately size reserve margins
- Procure fast-ramping resources or demand-response capacity only when needed
- Avoid unexpected load inflexibility that could lead to loss-of-load events

Mitigation is sufficient when the following conditions are met:

- Flexibility is modeled using real operational bounds
- The models explicitly represent load controllability attributes
- The models distinguish between firm and interruptible demand
- Assumptions are vetted with large load entities using data from actual load tests or validated technical documents
- Sensitivity scenarios evaluate adequacy across different flexibility levels, if appropriate (e.g., if load is fully interruptible vs. firm)

It is important to note that most resource planning models evaluate adequacy across an integrated hourly (or minute) time frame. Some large loads may exhibit high intra-minute volatility across normal operations that would need to be considered for appropriate balancing availability, like fast ramping resources. Large load entities should share this information with RPs. RPs should consider methods to ensure sufficient

resource adequacy and capabilities to support the unique characteristics and behavior of large loads, including intra-minute volatility.

This action is critically important. Inadequate modeling of large loads' behavior and flexibility can result in resource shortfalls during the tightest periods, compromising BPS reliability.

Simulate Transmission and Fuel Supply Constraints in Loss of Load Expectation Analysis

The NERC LLWG's *White Paper: Characteristics and Risks of Emerging Large Loads* and *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Load* discuss the need to include transmission system constraints and locational risk in resource adequacy assessments. The first white paper discusses the locational nature of reliability risks and the second white paper identifies gaps in modeling transmission constraints in resource adequacy studies. The NERC *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment* emphasizes the importance of modeling transmission-limited zones, deliverability, and non-firm transfers.

Large loads can be highly concentrated in specific locations and can shift locational demand profiles. They tend to cluster geographically near favorable conditions (e.g., low-cost power, substations), which may not have sufficient local generation or transmission. If loss of load expectation and Planning Reserve Margin studies do not incorporate local transmission constraints, they may miss localized capacity risks, especially during high load and outage scenarios, resulting in undetected reliability gaps.

Ignoring transmission limits in loss of load expectation modeling can result in the following:

- Underestimating zonal load-serving risk
- Hiding bottlenecks that delay energy delivery
- Generating overconfidence in system-wide adequacy

TPs, PCs, and RCs should coordinate with RPs to integrate transmission delivery limitations, if any, into loss of load expectation assessments. RPs may consider using network-aware ERA models as described in the NERC ERA *Technical Reference Document: Considerations for Performing an Energy Reliability Assessment*, including tools that support zonal reliability assessment, stochastic unavailability, and delivered load margin metrics.

TPs should provide current and planned constraints (e.g., congestion zones), transfer capabilities under normal and contingency scenarios (N-1, N-1-1), and weather-resilient infrastructure gap transfer capability curves for the relevant planning horizon. TPs and PCs should consider any transmission constraints associated with long-term transmission and generation outage work in both peak and off-peak seasons.

To the extent that emerging large loads have high load factors across the day, an increase in large loads may drive incremental reliance on specific fuel types, increasing vulnerability to common-mode fuel supply disruptions. RPs, PCs, and RCs should assess fuel supply and common-mode dependency risk by coordinating with gas system operators where applicable to assess cross-sector dependency risk. These assessments should be reflected in Planning Reserve Margin evaluations and resource procurement decisions.

Large load entities should provide accurate siting and expansion timelines to inform demand forecasts and expected reliability requirements. They should identify location, monthly or yearly buildout schedule, and reliability expectations (e.g., firm vs. interruptible interconnection) and share anticipated transmission service type (e.g., firm vs. non-firm).

This mitigation is complete under the following conditions:

- Resource adequacy simulations reflect forecasted transmission-related generation deliverability limitations (for example, transmission outages and congestion risk)
- The models reflect correlated outages (e.g., N-1-1 or weather-related) that can co-occur with large load peaks
- The assessment output identifies locational loss of load risk even in regions with high overall reserve margins
- The assessment output identifies locational loss of load risk in regions where zonal constraints exist

The importance of this mitigation is critical, and without location-aware analysis, risks may remain hidden in high-growth load pockets even when overall system adequacy appears sufficient. Without this, systems may appear resource adequate but fail under real-world locational stress.

Simulate Multiple Metrics for Resource Adequacy Assessments

Emerging large loads increase variability and systemic uncertainty, which can amplify loss-of-load events and increase exposure to low-probability, but high-impact, reliability risks.

As discussed in NERC's LLWG *White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, while resource adequacy planning traditionally focuses on ensuring sufficient generating capacity and reserves to meet expected demand using metrics like loss of load expectation and Planning Reserve Margin, it may not fully account for impactful combinations of large load peak consumption hours and resource outages. As a result, some dimensions of reliability risk—such as event duration, magnitude, and severity—may not be consistently reflected in current assessments. This missed information may lead to underestimation of system risk and underinvestment in flexible resources or infrastructure.

To mitigate reliability risk, RPs, where appropriate, should consider using the following:

- Multiple probabilistic metrics, consistent with existing NERC ERA guidance, to characterize different dimensions of reliability risks, such as loss of load hours, expected unserved energy, and conditional value at risk. These metrics provide information on the duration, magnitude, and severity of potential shortfall events.
- Probabilistic tools that support thousands of integrated weather, load, and generation scenarios and quantify reliability outcomes using scenario probabilities, rather than relying on a set of average or representative conditions. This can improve visibility in conditions where large load peak demand coincides with resource outages or extreme weather events.

RPs should use results to determine any need for additional mitigation such as flexible resources or increased reserve margins, if needed.

To support multiple probabilistic metrics, the large load entities should provide information on anticipated load profiles, operating characteristics, and expected behavior under normal and extreme events, such as granular load shape data, flexibility and curtailment capabilities, emergency response protocols, and modeled stress-event behavior (e.g., when tripped or derated). Where applicable, large load entities should also provide information on expected availability and operational constraints of on-site and BTM resources.

The mitigation may be considered sufficient when the following is true:

- Studies produce multiple probabilistic adequacy metrics across multiple scenarios
- Metrics are validated, where appropriate, through comparison with historical events or stress-testing under extreme but plausible system conditions

The importance of this action is critical. This enables an understanding of reliability risk under uncertainty introduced by emerging large loads. Without expanded metrics, RPs risk being surprised by rare, severe outages that aggregate metrics like loss of load expectation cannot detect.

Chapter 4: Operations and Balancing

In the operations horizon, system operators are responsible for ensuring that the BPS is reliable and secure. This includes ensuring that load and generation are balanced, which is required to maintain stability. This chapter covers recommendations for entities to ensure reliable operations of the BPS via risk mitigations in commissioning processes, real-time operations, and balancing.

Commissioning Process

In power systems engineering, commissioning is typically the process used to bridge from a planned facility interconnection to real-time operations. Commissioning can include data verification activities, additional studies, and physical preparations of the site to enable successful and reliable BPS operations.

TOs in coordination with RCs, BAs, TOPs, and TPs should establish a comprehensive commissioning process that ensures operational readiness for large loads. Additionally, it may be appropriate to perform some commissioning tests again as new parts of the facility are energized, considering that many large loads have a tiered buildout schedule that can last months to years.

Commissioning processes established by the abovementioned entities should include the following:

- Verification of communications including, but not limited to the following:
 - Real-time large load entity contact for operational communications
 - Installation and testing that live telemetry such as supervisory control and data acquisition (SCADA) and phasor measurement unit (PMU) are sending and receiving as intended
 - If participating in demand response, testing of demand-response signals and successful deployment of demand response
 - Verify demand-response capability consistent with BA and TOP requirements for inclusion in Emergency Operating procedures
- Prior to energization of the large load facility, ensure that the loads are properly accounted for in load forecasting and other operational modeling, like outage coordination and day-ahead studies
- TOs, RCs, and BAs, in coordination with large load entities, should conduct commissioning tests of the large load during interconnection and test the load facility's ramp ability and max consumption
- Should require the large load facility to be studied in a near-term operational planning assessment, in coordination with the TP, PC, TOP, and RC, that includes all large load facilities nearing their energization date
- Should require comprehensive dynamic model verification process prior to energization
- Should require comprehensive dynamic model validation process to verify the large loads performance during and after commissioning
- After energization, if end-user facilities seek to make qualified changes, appropriate studies and commissioning processes should be performed
- Large loads should validate design and performance criteria in the interconnection requirements after energization and during commercial operation
- Ongoing post-commissioning testing and verification between TOP, BA, RC, and large load entity for large load facility configurations, settings, communications, and personnel contacts

As the maximum consumption of a large load facility may increase over time, some requirements of the commissioning process may need to be repeated when the maximum consumption is increased or a significant change to the facility occurs.

Real-Time Monitoring

To support real-time operational functions like short-term forecasting, balancing, and event analysis, entities mentioned in [Chapter 1](#) should collect real-time and post-event data as needed to support analysis and other processes that ensure reliability.

Short-Term Forecasting

While “short term” is not explicitly defined, throughout this chapter short term is generally defined to mean anywhere from one hour to seven days, depending on the specific context. Some large loads, including computational loads, pose new challenges for short-term operational forecasting by RCs, BAs, and TOPs. Some of these loads can be highly variable and exhibit both second-to-second and minute-to-minute power oscillations along with fast ramping capabilities. If large loads are not considered in short-term forecasting, the BA could under-commit generation in real time, potentially leading to reliability issues and load shedding.

Load forecasting information from large loads is critically important for BAs to assess risks to energy adequacy under BAL-007 and to ensure appropriate unit commitment and dispatch. TOPs in consultation with BAs should establish required large load forecasting information needs and timing of updates. The large load entity may need to provide near-term hourly net-load forecasts and planned outages to ensure sufficient load forecasting.

Load Coordination in Demand-Response Programs

DPs and TOs should consider whether it is appropriate to register large loads in demand-response programs if the large load is willing to participate and can be flexible. This will allow for the load to be managed as needed to address operational conditions. The TOP, RC, and BA should require large loads to submit their current operating plans that provide a forecast for the next seven days to align with BAL-007 Near-Term Energy Reliability Assessments. Without participation in demand-response programs or the submission of current operating plans, the system operator will find it challenging to properly account for large loads in their forecasts and thus energy and ancillary service procurement and operational planning.

Operational Analysis of Load Behavior

The best source of a short-term forecast would be directly from the entity that controls the demand of the large load facility. The large load entity should provide, and the BA and RC should require the large load entity to provide, near-term demand forecasts and Operating Plans as well as real-time telemetry.

Once the large load has become commercial, the TOP, RC, and BA should review the large load’s normal operational behavior to assess how it matches against their forecasted load consumption predictions.

TOPs, RCs, and BAs should monitor large loads and observe their load usage patterns to inform short-term forecasting. This will allow them to understand current and past behaviors for forecasting models.

Balancing and Reserves

To ensure the reliability of the BPS, the BA must ensure that load and generation are constantly balanced. Given the ability of large loads to ramp hundreds of MWs in seconds as documented in *White Paper: Characteristics and Risks of Emerging Large Loads*, this poses a challenge for BAs to maintain the load and

generation balance given the highly variable load profiles. Failure to maintain this balance could lead to increased risk to the frequency stability of the BPS.

Balancing Reserve Management

Large loads that operate with limited grid visibility, no coordination with BAs, and no ride-through obligations can lead to system imbalance. Abrupt load changes or disconnections lead to system imbalance, unanticipated ACE swings, regulation reserve exhaustion, and frequency instability, especially during disturbances. Large, fast-varying loads can rapidly swing demand by tens or hundreds of MW within seconds or minutes. These swings strain balancing reserves and frequency control, especially if BAs lack telemetry or coordination with the load operators.

BAs should consider incorporating large load variability in assessments to aid in maintaining sufficient regulating capability and coordination to handle these demand swings while staying within CPS1 and BAAL limits. This reduces the chance that an unpredictable 500 MW load surge or drop will result in ACE excursions that jeopardize frequency stability or violate reliability criteria. In essence, the BA should “bring the large loads into the loop” of frequency control (either by securing more responsive resources or by working with the load operator to smooth out changes), thereby maintaining balance and compliant performance. Requiring granular telemetry and data for large loads closes the visibility gap that currently exists.

Large load entities, in coordination with their TOs, BAs, and RCs, should perform the following risk mitigations:

- Coordinate with the TO to provide real-time measurements of key electrical quantities (real power, reactive power, and voltage) of each large load facility (if not already monitored by TO as mentioned in [Chapter 1](#))
- Provide near-term demand forecast from as little as five minutes in advance to as much as seven days in advance (as mentioned in [Chapter 1](#)), including advance notice of substantial load changes (e.g., planned step changes)
- Register points of contact
 - Assign operational contacts at the large load facility for 24/7 grid coordination with TOP, BA, and RC

BAs, in coordination with TOPs and RCs, should perform the following risk mitigations:

- Specify any interconnections design requirements to TOs in their footprint for inclusion in the TO’s interconnection requirements (FAC-001) to maintain grid reliability, such as operational ramping limits, interconnection/integration process requirements, communication protocols, and monitoring equipment
- BAs, TOPs, and RCs should each specify any data requirements to large loads necessary to perform operational and real-time analysis and monitoring, such as models and load forecasting
- Identify any “large loads” in their area (e.g., above a MW threshold and/or high ramp rate) and incorporate their expected behavior into operations; examples include the following:
 - Adjusting AGC parameters or supplemental regulation reserves to cover large load demand fluctuations
 - Establishing coordination protocols with the load or its serving entity to manage or mitigate sudden demand changes

- When performing unit commitment and reserve considerations, prepare to handle the largest expected decrease in demand due to large load ramping, customer-initiated load reduction, load loss as a contingency, and TPL-001²⁷ contingencies that could cause loss of one or more large loads (these may require coordination with TPs and PCs along with dynamic simulations)
- Incorporate load volatility in reserve planning by adjusting regulating and contingency reserve needs using scenario analysis that reflects large load variability
- Require large load curtailment participation by establishing programs for voluntary or automated demand modulation from large loads during regulation scarcity

TOPs should do the following:

- Enable situational awareness by using EMS displays or tools to show large load status and ramp rates
- Coordinate events with BAs by notifying BAs of any unplanned load deviations or outages

In absence of these mitigations, system operators will lack real-time insight into the most volatile loads on the system, directly compromising frequency control, reserve deployment, and reliability metrics like ACE.

Large Load Ramping and Effect on Area Control Error

Large loads with highly variable demand profiles can present challenges in controlling the ACE, as their demand can be difficult to forecast even hours or minutes in advance. Additionally, as mentioned in the **Customer-Initiated Load Reduction and Load Loss** section, transmission faults that lead to CILR can result in large amount of rapid demand reduction. If left unmitigated, these deviations can result in system-wide reliability issues, such as frequency excursions and eventually cascading outages. As the first step to successfully manage ACE in real time, BAs should obtain the necessary information from large loads to support BA analysis functions, real-time monitoring, and near-term energy reliability assessments (e.g., TOP-003 and BAL-007).

Mitigating the Impact on ACE from Load Variability

Large loads can introduce significant variability and fluctuations on a second-to-second, minute-to-minute, and hourly basis. The frequency and magnitude of these fluctuations can put significant strain on a BA to successfully manage ACE.

The ability of a BA to manage potential fluctuations of large loads is dependent on corrective actions at its disposal, considering factors such as the following:

- AGC dispatch time intervals
- Units available for frequency regulation/AGC
- Operating Reserves available

Furthermore, most current BAL standard metrics focus on performance across 30-minute intervals or greater, which may not account for performance risks associated with highly variable ACE deviations on an intra-minute basis. If these risks are not mitigated, it puts the burden not only on the interconnected BA but on the entire interconnection.

²⁷ [TPL-001-5](#)

The traditional dispatch hierarchy of a) unit commitment ensuring that adequate supply is available to meet projected needs, b) dispatch being utilized to follow load and inter-tie transactions at defined intervals, and c) frequency regulation leveraged to manage intra-dispatch variability may be inadequate to manage projected variability from large loads.

Risk mitigations to manage impacts of variability include the following:

- Large load entities should minimize variability via large load facility software mitigations, large load facility hardware mitigations²⁸
- TOs should consult with and incorporate any BA-specified requirements necessary to maintain ACE and reliability into their interconnection requirements²⁹

Mitigating the Impact on ACE from Customer-Initiated Load Reduction

High amounts of load reduction or loss for a single contingency or event can present significant challenges to BAs in maintaining ACE if scheduled regulating-down frequency regulation service is insufficient. Compounding this challenge is that large loads may self-isolate from the grid for minutes or hours before reconnecting. If the BA is forced to decommit generation to maintain ACE for the initial load loss, there may be insufficient dispatchable generation on-line or regulating-up frequency regulation service to maintain ACE when the large loads reconnect or ramp up to return to their normal or expected consumption levels.

Therefore, BAs in coordination with their TOs, TPs, and PCs, similar to generation most-severe single contingency (MSSC) requirements in BAL-002 and BAL-003, should identify and incorporate their most severe load contingency for loads into their unit commitment and reserve considerations. The development of a most-severe load contingency should consider CILR events as well as other traditional contingencies. Importantly, this relies on the TP and PC obtaining accurate dynamic load models of large load facilities and their low-voltage ride-through behavior.

TOs should, in consultation with BAs, establish operating protocols with large loads that document expected behavior of large loads when reconnecting or ramping back up to expected load levels.

Real-Time Operations and Coordination

Large loads can impact real-time operations in various ways that need to be coordinated. As described in *White Paper: Characteristics and Risks of Emerging Large Loads*, a reliability concern is that some large loads are interconnecting to the grid for the first time within the near-term transmission planning horizon (five years). To mitigate this, TOs should establish requirements as described in the following sections in their interconnection agreements prior to energizing for the first time to ensure reliable coordination between large loads and system operators. This coordination should be completed using similar processes for generators and/or transmission being energized and connected for the first time.

Voltage Control and Coordination for Point of Interconnection

TOs, TPs, and PCs should coordinate to establish allowable power factor ranges for the large load point of interconnection as well as establishing allowable reactive power and voltage controls (e.g., sub-transient, transient, steady-state) for the large load.

²⁸ E. Choukse et al., *Power Stabilization for AI Training Datacenters*, arXiv.org, August 2025. <https://arxiv.org/html/2508.14318>

²⁹ At a minimum, this should include the establishment of operational load ramp rate limits (e.g., MW/min) for large loads in normal and post-disturbance scenarios

Outage Coordination Process Updates Incorporating Load

For established large loads, the outage coordination reliability requirements are needed to ensure that near-term assessments and real-time operations are evaluated properly. This is consistent with IRO-017 to maintain an outage coordination process for generation and transmission. Importantly, TOs and DPs should coordinate with large load entities to report forced and planned outages of large load facilities to relevant grid operators (TOPs, BAs, and RCs) in a timely fashion (as determined by the TOP, BA, and RC). RCs should establish operating protocols that include process(es) for coordinating planned outages consistent with IRO-017 for generators and transmission.

Analysis of Customer-Initiated Load Reductions in Real-Time Contingency Analysis

TOPs and RCs should incorporate steady-state contingencies representing customer-initiated load reduction events into real-time contingency analysis (RTCA) and in operations studies. If it is found that a customer-initiated load reduction event of one or more large loads could occur for a contingency, then the RTCA contingency list should be updated accordingly to reflect the behavior of the large loads without having to run online dynamic analysis in real-time.

Large Load Communication Requirements

Large loads can impact the reliability of the BPS if their real-time operations are not aligned with the operational criteria defined by the RC, BA, and TOP. This includes ramp rate limits, real-time dispatchability, providing day-ahead schedules, and data sharing. Similar to a generator, unexpected operations by a large load may raise concerns about balancing reserves and maintaining system reliability within system operating limits.

As mentioned in *Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads*, large loads are not registered entities at the time of this guideline's initial publication and are not obligated to establish real-time communication with utility operators. The following recommended actions will help align large load entity responsibilities with those of existing registered entities, ensuring a coordinated response during critical events and improving overall system reliability.

Establish Interpersonal Communication Capabilities

Require large loads to develop and maintain interpersonal communication capabilities that are essential for maintaining system reliability. This would be similar to the requirements set forth in COM-001 for GOPs. By implementing this requirement, large loads would be better equipped to communicate effectively with system operators, reducing the potential for miscommunications during critical situations.

Training and Adherence to Operating Instructions

Large load operators should undergo training and adhere to Operating Instructions akin to the standards outlined in PER-005 and COM-002 for GOPs. This would ensure that large load entities are well-prepared to respond appropriately during emergencies, thereby enhancing operational efficiency and safety.

Response to Operating Instructions

Require operators of large loads to respond promptly and effectively to Operating Instructions issued by RCs, BAs, and TOPs as outlined in TOP-001 and IRO-001.

Event Analysis Process Changes

During normal grid operations, it is expected that the BPS will experience faults leading to disturbances and protection system operations. After such an event, the TO will typically conduct a review to analyze how the

system performed to ensure that the BPS operated within its design criteria. With the increasing deployment of large loads, this event analysis process should be updated.

Additionally, large loads, as part of interconnection requirements, should provide all necessary information needed for TPs, PCs, BAs, TOPs, and RCs to conduct post-event analyses and assessments.

TOs and TOPs should coordinate with large load entities to have a monitoring system in place to ensure that the most up-to-date data is provided to BAs and RCs and other interested parties.

The following processes are recommended to help mitigate the risks associated with collecting data for event analysis:

- Develop tools and applications to identify abnormalities and root causes, trigger alarms and send notifications, display events, and create event reports
- Develop monitoring strategy in coordination with large load entities for monitoring large load facilities and incorporate corresponding requirements in TO's interconnection requirements and/or TOP's operating agreement documents
- Develop pre-energization and ongoing event validation processes/procedures:
 - Identify monitoring locations and develop a monitoring system to support real-time situational awareness and quick event data retrieving, including power quality monitor data, relay fault data, sequence of events, and phasor measurement unit recordings
 - Pre-energization validation to ensure the TOP is capable of monitoring the large load as designed in its real-time control center before it is declared ready for operation per applicable requirements/agreement
 - Ongoing event validation to help assess control setting performance per the large load facility design criteria, which may be performed on a periodic basis (as applicable)

Chapter 5: Stability

As outlined in the first LLWG white paper, large loads can significantly impact the stability of the BPS. As stated in **Chapter 2**, TPs and PCs should perform required steady-state and dynamic studies under FAC-002 using the best available models provided by the large loads to identify the impacts and coordinate with the large loads to mitigate any risks pertaining to the BPS.

Major reliability risks may remain hidden when large loads are not accurately represented in these studies, leading to unforeseen stability issues, such as the unexpected widespread tripping of large loads because of a nearby fault. Additional consideration should be given to stability studies for large loads sited with BTM generation. As mentioned in **Chapter 1**, TOs and DPs, in coordination with TPs and PCs, should create interconnection request requirements that establish a minimum set of data and milestones that must be achieved prior to energizing a new large load facility (or qualified changes, as is relevant). This minimum data requirement should allow for the large loads to be fully and properly studied per FAC-002. The dynamic models provided by large load entities should accurately demonstrate, at a minimum, the characteristics mentioned in **Chapter 1**.

Voltage and Frequency Disturbance Performance

Some large loads, like data centers and cryptocurrency mining facilities, are voltage sensitive and there are documented incidents of large loads unexpectedly reducing demand from the utility supply during and after normally cleared faults.^{30,31,32} CILR in small quantities may not adversely impact BPS reliability, but at certain megawatt thresholds, CILR can cause cascading outages on a time scale of cycles to seconds. The acceptable CILR threshold depends on local and interconnection-wide factors like system strength and inertia.^{33,34} Thus, studying CILR events is a crucial part of ensuring reliable BPS operations. Large loads have not demonstrated similar sensitivity to frequency excursions.

To study the impact of large load disturbance performance on grid reliability, large load entities should provide accurate dynamic models that demonstrate frequency and voltage facility-level disturbance performance (e.g., tripping, switchover, reductions, reconnection) to the TO, TP, and PC. The term “trip” refers to disconnection from the grid either due to the action of a protection device or due to switchover to an alternate source of energy like a battery in the large load facility uninterruptible power supply (UPS). TOs should update their interconnection agreements to require that this data be provided. For existing facilities, TOs should obtain voltage and frequency disturbance performance settings from large load facility owners that are verified via documentation from the OEM-provided operation manual of the equipment inside the facility. TOs should coordinate with new and existing large load entities to communicate disturbance performance requirements for their areas. Large load entities should consider operational procedure changes and firmware upgrades, among other things, to ensure that their new and existing facilities can meet the disturbance performance requirements defined by the TO, TP, PC, BA, and RC.

³⁰ NERC, *Incident Review Considering Simultaneous Voltage-Sensitive Load Reductions*, January 2025.

https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_large_load_loss.pdf

³¹ A. Springer, *Large Loads in ERCOT—Observations and Risks to Reliability*, presented at the Large Loads Task Force Kickoff Meeting, October 2024, pp. 20–54. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_kickoff_presentations.pdf

³² NERC, *Incident Review Voltage-Sensitive Crypto Load Reductions*, January 2026. https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_considering_voltage-sensitive_crypto_load_reductions.pdf

³³ L. Hinojosa, *Load Loss Threshold Analysis*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

³⁴ J. Billo, *Large Electronic Load (LEL) Voltage Ride-Through Overview*, presented at the ERCOT Large Load Workshop, June 2025, pp. 1–18. https://www.ercot.com/files/docs/2025/06/13/COMBINED_June-2025-Large-Load-Workshop.pptx

If the disturbance performance model is not available for an as-built design of an existing large load facility, the TOs and TPs should require, and large load entities should provide, an updated disturbance performance model that accurately demonstrates the real behavior of the large load facility. Additionally, models for new and existing large load facilities should meet relevant model quality tests established by the TPs and PCs.

TOs, TPs, PCs, BAs, and RCs should coordinate to determine local and system-wide thresholds for the magnitude of rapid demand change their area can withstand without violating frequency or voltage stability limits. They should use the results of these studies to inform the need for establishing minimum voltage and frequency disturbance performance requirements including: rate-of-change of frequency (RoCoF) ride-through requirements, phase-jump considerations, low-voltage ride-through, high-voltage ride-through, or transmission mitigations to reduce system risk specific to their region in the interconnection requirements. TOs, in consultation with BAs, RCs, and TOPs, should establish these requirements for large loads considering the similar requirements for generating resources (e.g., PRC-019, PRC-024 and PRC-029). Ride-through requirements should be established on a per-interconnection basis to ensure that system-wide needs are met while avoiding mismatched ride-through performance and protection/automated transfer settings. Additionally, the frequency ride-through may not trip zone should be coordinated with UFLS trip settings.

In addition to disturbance performance criteria, if TPs determine that an uncontrolled load disconnection poses a risk to system stability, the TO, TP, PC, and RC should take actions to protect the reliability of the BPS. This could include imposing demand limits on large loads (i.e., establishing large load curtailment as a System Operating Limit),³⁵ installing dynamic reactive devices that can either prevent voltage sags from affecting the facility or prevent over-voltages resulting from sudden loss of the large load facility, or making other system changes as needed, such as having the BAs commit fast downward responsive resources that can manage the system overfrequency resulting from sudden load disconnection.

Large load entities should design their facility, including equipment protection and control settings, to accommodate the disturbance performance requirements in the interconnection requirements and coordinate with TPs and PCs on voltage and frequency ride-through settings.

While establishing disturbance performance criteria for large load facilities, generator overfrequency limits should be considered to avoid cascading generator tripping. PRC-024 requires GOs to set their generator frequency protective relaying such that the relaying scheme does not trip the generator within the “no trip zone” of PRC-024 Attachment 1 with some exceptions. Attachment 1 requires continuous operation if the system frequency is less than 60.5 Hz for the Eastern Interconnection and 60.6 Hz for all other Interconnections. Outside of the continuous operation zone, there is a timeline associated with when generators may trip. For example, in the Western Interconnection, generators may trip after three minutes of the grid frequency remaining over 60.6 Hz. As a result, operators should aim to arrest the frequency zenith to less than 60.6 Hz for CILR events. ERCOT has set its official overfrequency limit at 60.4 Hz in the transient time frame,³⁶ citing that not all generators can withstand a frequency of 60.6 Hz. GOs should assess the capability of their generator equipment and facility-level protection to withstand the upper frequency limits and should inform BAs, TOs, TPs, PCs, and RCs of their equipment limits so they can be considered in large load ride-through analysis as required by R3 of PRC-024. Additionally, all GOs should assess the capability of their facilities and protections to ride-through the high RoCoF conditions that may occur during CILR events.

TOs, in coordination with TPs, PCs, RCs, and BAs, should create requirements for large loads co-located with generators (connected through the same point of interconnection) to coordinate disturbance performance.

³⁵ J. Billo, *Large Load Voltage Ride-Through Related Studies*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, August 2026. <https://www.ercot.com/calendar/08142025-LLWG-Meeting>

³⁶ L. Hinojosa, *Load Loss Threshold Analysis*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

Additional consideration should be given to the fact that many existing IBR facilities are already subject to PRC-029 which specifies ride-through criteria for IBRs (and PRC-024 for synchronous machines). Subsequently, GOs, large load entities, and TPs and PCs should coordinate disturbance performance between co-located generators and large load facilities (connected through the same point of interconnection).

Voltage Stability

Voltage instability caused by large loads can result in low- or high-voltage conditions, increased reactive power demand, and potential voltage collapse. To mitigate these risks, a structured approach across the planning, interconnection, and operational domains should be adopted. TOs should require large load entities to submit voltage ride-through curves, reactive power capabilities, and UPS/tap-changer control settings as part of the interconnection package and ongoing data updates. This will facilitate the appropriate simulation of voltage recovery behavior under disturbances.

TPs and PCs should incorporate PSPD and EMT (if appropriate) dynamic models that adequately represent voltage-sensitive protections and controls. This allows evaluation of short- and long-term voltage recovery and dynamic reactive requirements. For large load facilities, utilities should consider their net load shapes (in case they have BTM generation) and the use of on-load tap changers (OLTC) at large load facilities to assess their impact on long-term voltage stability. Long-term voltage stability analyses are performed using the classic P-V/Q-V analyses in power flow domain. For large load facilities, one should consider their net load shape to identify the loading levels during peak load conditions (where voltage stability issues generally appear). Additional studies may be needed for off-peak conditions where voltage instability may occur. Studies should also consider if any BTM or co-located generation is available to mitigate the voltage issues. Where necessary, TPs should assess the potential need for dynamic reactive support such as static VAR devices or synchronous condensers.

TPs and PCs should run contingency-based voltage assessments that include realistic load trip/reconnect behaviors, evaluating system VAR margins and identifying locations where rapid voltage recovery is not possible. TOs should coordinate with RCs and TOPs to define restoration sequences that avoid simultaneous reconnection of large blocks of load. Real-time alarms should be configured to detect declining voltage stability margins (e.g., low-Q reserve). Voltage-related event analysis should include comparison of observed large load behavior to modeled expectations, with models adjusted accordingly. Post-event findings should inform ongoing model improvements and settings refinements.

TPs and PCs should also assess voltage stability, including under/over-voltage performance, the potential need for under/over-voltage protection schemes, and the impact of CILR events (as discussed in [Customer-Initiated Load Reduction and Load Loss](#)).

These voltage stability mitigation practices should be reflected in the interconnection agreement and assumptions should be updated periodically with operational data and commissioning results.

Frequency Stability (Overfrequency)

Rapid changes in real power demand, including large load reductions or ramping, may introduce frequency disturbances and instability. The most consequential and credible mechanism observed to date is aggregate CILR following transmission faults. These events create a nearly instantaneous imbalance where generation exceeds demand by the amount of CILR. The large imbalance of generation and load drives system frequency upward at a rate determined by the magnitude of load reduction, the interconnection's online inertia, and primary frequency response. The largest RoCoF would be observed when interconnection inertia and

available primary frequency response are at minimums. The three primary variables involved in this problem are largest aggregate CILR, online inertia, and frequency-responsive reserves.

The first variable to consider when analyzing overfrequency risk is the largest aggregate CILR. The largest aggregate CILR is dependent on the location of the fault, the amount of nearby voltage-sensitive load, generator fault contribution, and system topology. Accurate dynamic models of the loads in the area are crucial, including load voltage dependence for stall and forced reduction. The risk is higher in areas where generator fault contribution is lower, and more voltage-sensitive loads are in close proximity. All these factors should be considered when determining and simulating the largest aggregate CILR contingency. With accurate dynamic models of the system, generators, and the large load facilities, all these factors should be demonstrated. To accurately simulate the largest aggregate CILR, TOs should collect, and large load entities should provide, detailed information on voltage conditions and timing that will cause large load facilities on their system to reduce output or disconnect from the grid. This is commonly referred to as low-voltage and high-voltage ride-through characteristics. As mentioned in **Chapter 1**, TOs should collect, and large load entities should provide, dynamic models that accurately represent behavior from all devices that affect facility-level disturbance performance such as the UPS transfer logic and backup generator synchronization, which should be modeled and validated in dynamic simulation studies (e.g., via PSPD or EMT tools). This should include delay logic, reconnection criteria, and voltage/frequency tolerance ranges. TOs should share the collected dynamic modeling information with their TP and PC. This dynamic model should go through model verification and model validation processes, as mentioned in **Chapter 1**.

On an ongoing basis, TPs should use large load facility dynamic model information to assess and report to their BA the largest credible CILR due to a worst-case fault on their system. TPs should also plan the system in such a way that the largest credible load reduction is limited to a level that is acceptable for the BA and PC regions in which they operate.

The second variable of frequency stability for CILR events is the amount of on-line inertia, which is variable and depends on what synchronous generators are on-line. CILR events that happen when inertia is lowest will have the highest RoCoF, though overfrequency risk may be highest when inertia is low and downward reserves are low. BAs and RCs should account for the expected amount of on-line inertia when procuring Operating Reserves that will adequately ensure reliability given the worst case CILR event.

The third variable of frequency stability for CILR events is the amount of on-line frequency-responsive reserves. These reserves are comprised of on-line generation with legroom (generally defined as real power generation minus minimum real power capability of the unit) that has been tested and verified to be capable of providing downward droop response as described in the *Primary Frequency Control Reliability Guideline*.³⁷ Resources capable of providing fast frequency response will also have a major effect on the arresting of overfrequency conditions.

To mitigate the risk posed to frequency stability, PCs in each Interconnection should analyze and study the worst-case scenario(s) where the system is shown to have at- or near-minimum inertia and primary frequency-responsive reserves. The analysis should include the worst-case fault(s), analyze system frequency stability, and identify any generators that may trip off-line. The findings of these frequency stability studies should be shared with BAs so that they may make more informed decisions during unit commitment and reserves coordination.

³⁷ NERC, *Primary Frequency Control Reliability Guideline*, September 2023. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/primary_frequency_control_reliability_guideline_v_4.0_clean_v3---dr.pdf

Through a combination of the aforementioned risk mitigations to frequency stability risks, interconnection frequency should remain stable and not infringe on any overfrequency limits that may impact reliable BPS operations (cascading generator trips). If the system frequency is shown to be stable in simulation and in practice for worst-case or near worst-case scenarios, the risk is deemed to be mitigated.

Oscillation Mitigation

Certain large loads with variable and cyclical profiles, such as AI data centers and electric arc furnaces, can introduce forced oscillations into the BPS. These loads often operate cyclically. If the frequency of load cycling is in the electromechanical range (i.e., 0.1–2 Hz for inter-area and local modes), there is a potential for interacting with natural low frequencies and causing widespread forced oscillations.³⁸ Such oscillations pose significant risks to the BPS and should be studied before these loads are energized.

Additionally, other complex dynamic control interactions have been demonstrated to cause oscillations, including one cryptocurrency mining facility in ERCOT³⁹ and one data center in Dominion. For oscillations at higher frequencies, risks of subsynchronous control interactions (SSCI) or subsynchronous torsional interactions (SSTI) exist. These risks need special consideration in studies and monitoring, especially for large loads co-located with generators.

TOs should consider incorporating monitoring and mitigation provisions in interconnection agreements to address potential oscillatory behavior. TOs and RCs should revise their oscillation monitoring and mitigation platforms and procedures to account for potential load-induced oscillations. If wide-area oscillations are observed, coordinated actions by multiple RCs may be needed to address the reliability concern. RCs should incorporate large load-specific actions in their coordination plans. Adverse reliability impacts from oscillations that occur may be mitigated through coordinated use of supplemental controls.

Additionally, TOs, TPs, PCs, and RCs should collaborate to establish requirements for large loads to avoid exciting specific modes of the local system and interconnection.

Cyclical power demand from large load facilities can significantly impact the stability of electric grids. In order to properly study the effects of cyclical demand, the high-speed FR and DDR data mentioned in [Chapter 1](#) should be collected. This fluctuating demand has the potential to excite torsional modes in nearby generators, leading to mechanical stress and potential damage. It can also interfere with the natural modes of other equipment, such as the controls of IBRs. Additionally, large load facilities should be assessed for their potential to contribute to oscillatory instability. This can occur under certain grid conditions if device controls in large load facilities interact unfavorably with the network impedance or other nearby equipment, potentially leading to underdamped, growing, or sustained power oscillations.

As these system interactions can cause significant risk to the local transmission system, generators, and the entire interconnection, the TO should also incorporate monitoring and protective equipment requirements for large loads as required by the TOP and RC. Large load entities should also incorporate monitoring and protective equipment that allows them to validate that the large load facility meets the TO's performance requirements. Some specifications for the types of devices required are given in [Chapter 1](#). TPs, PCs, and large load entities should consider the following recommendations to identify mitigation and reduce potential risks associated with oscillation.

³⁸ NERC, *Eastern Interconnection Oscillation Disturbance Forced Oscillation Event*, January 2019.

https://www.nerc.com/globalassets/our-work/reports/event-reports/january_11_oscillation_event_report.pdf

³⁹ P. Gravois, *Large Load Oscillation Event*, presented at the ERCOT Large Flexible Load Task Force (LFLTF) Meeting, March 2025.

<https://www.ercot.com/calendar/08142025-LLWG-Meeting>

To support both proactive and post-event mitigation, the following practices are recommended:

- **Detection and Mitigation:**
 - As mentioned in [Chapter 1](#), high-speed recording devices should measure data at the large load facility.
 - Data from these monitoring devices should be incorporated into existing oscillation detection and source identification platforms that the TOs and RCs are using. TOs should determine the appropriate monitoring equipment to accurately capture the desired frequency content.
 - TPs and PCs should proactively gather data to gain an understanding of what the load pattern would be like both in terms of amplitude and frequency content.
 - In the operations time frame, if the TO, TOP, or RC detects low-damping conditions for a natural mode, they can consider establishing mechanisms to request large loads to defer oscillatory behavior as long as the low-damping conditions persist.
 - Large load entities owning and operating AI training data centers, as directed by TOs, TPs, PCs, and RCs, should implement necessary mitigations to meet oscillation damping metrics and thresholds including software mitigations, GPU power smoothing, and rack-level energy storage.⁴⁰
- **Interconnection Processes:**
 - TPs and PCs should provide expected system strength ranges at the POI for equipment validation.
 - TPs and PCs should establish oscillation attenuation metrics and real power amplitude variation thresholds that loads must meet under interconnection requirements. They should also establish limits (amplitude and frequency) on oscillatory demand from large load facilities depending on the risk of subsynchronous resonance (SSR) or exciting any inter-area and local modes. Approaches range from facility-specific requirements to system-wide requirements.⁴¹ An empirical rule that may be followed is avoiding natural frequencies excitable from a large load location. These frequencies and high-risk locations may be identified through planning studies.⁴²
 - TPs and PCs should study interconnections in weak grid areas or locations and identify mitigation if needed. To support this requirement, additional criteria beyond SCR should be considered. For a load co-located with a generator, there is no clear guidance on whether the SCR should be calculated based on load rating, generator rating, or net load rating.
- **Monitoring Requirements:**
 - High-resolution monitoring as detailed in [Chapter 1](#) and [Chapter 4](#) can support real-time oscillation detection and post-disturbance verification of load behavior. Additionally, grid operators should identify load facilities that are contributing to oscillations, informing mitigation actions that could include isolating the source load. Accurate characterization of frequency signals above 5 Hz may require point-on-wave measurements.⁴³ Exact sample rates, technology

⁴⁰ E. Choukse et al., *Power Stabilization for AI Training Datacenters*, arXiv.org, August 2025. <https://arxiv.org/abs/2508.14318>

⁴¹ ERCOT, *Large Electronic Load Sub-Synchronous Oscillation (LEL-SSO) Power Variation Challenges and Discussion*, presented at the ERCOT Large Load Working Group (LLWG) Meeting, January 2026. <https://www.ercot.com/calendar/01222026-LLWG-Meeting>

⁴² S. Biswas, A. Varghese, K. Chatterjee, et al. *Evaluating the Risk to Bulk Power System Reliability from Large Load Induced Oscillations*, TechRxiv. November 2025, doi: <https://doi.org/10.36227/techrxiv.175623878.87007943/v2>

⁴³ J. Follum et al., *Phasors or Waveforms: Considerations for Choosing Measurements to Match Your Application*, April 2021. https://www.naspi.org/sites/default/files/reference_documents/pnnl_31215_follum_phasors_waveforms.pdf

types, and post-processing needs may depend on the specific phenomena being analyzed and monitored.

- Data from these monitoring devices should be incorporated into existing oscillation detection and source identification platforms that the TOs and RCs are using.
- **Event Analysis and Model Validation:**
 - If a TO or TOP determines that a large load facility is contributing to system oscillations, the TP and PC should conduct post-event analysis using as-built models to assess damping behavior and determine if any equipment will need to be installed to mitigate the oscillation.
 - Time-synchronized PMU, POW, and SCADA data should be analyzed to compare observed response with simulation expectations. Model adjustments should follow as needed.
 - Where oscillatory behavior is observed, TOs and RCs may consider protective relaying schemes or disconnection logic as part of a broader effort to safeguard grid stability.

Angular Stability

Angular instability may arise in systems with significant CILR events or rapid real power demand fluctuations, particularly during faults in weak or constrained areas. While this risk is often less emphasized than voltage or frequency stability, under certain network conditions, it may result in inter-area angle swings or loss of synchronism. GOs should consider when to implement out-of-step relaying at key interfaces to detect and isolate unstable swings promptly. See [Figure 5.1](#) demonstrating loss of synchronism in a PSPD simulation.

Recent industry experience highlights a specific angular stability concern involving large loads co-located with generation in areas with weak transmission connectivity.⁴⁴ In such scenarios, the sudden loss of load can leave nearby generators without sufficient transmission capacity to evacuate power to the broader grid, leading to large angle swings or potential loss of synchronism. This condition is particularly pronounced when both the generation and load are part of a combined facility with limited ties to the rest of the system.

⁴⁴ M. Peterson, "Data Center Interconnection Studies & Challenges," presented at the Large Loads Task Force Meeting and Workshop, Apr. 2025, pp. 53–65. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_april_meeting_technical_workshop_presentations.pdf

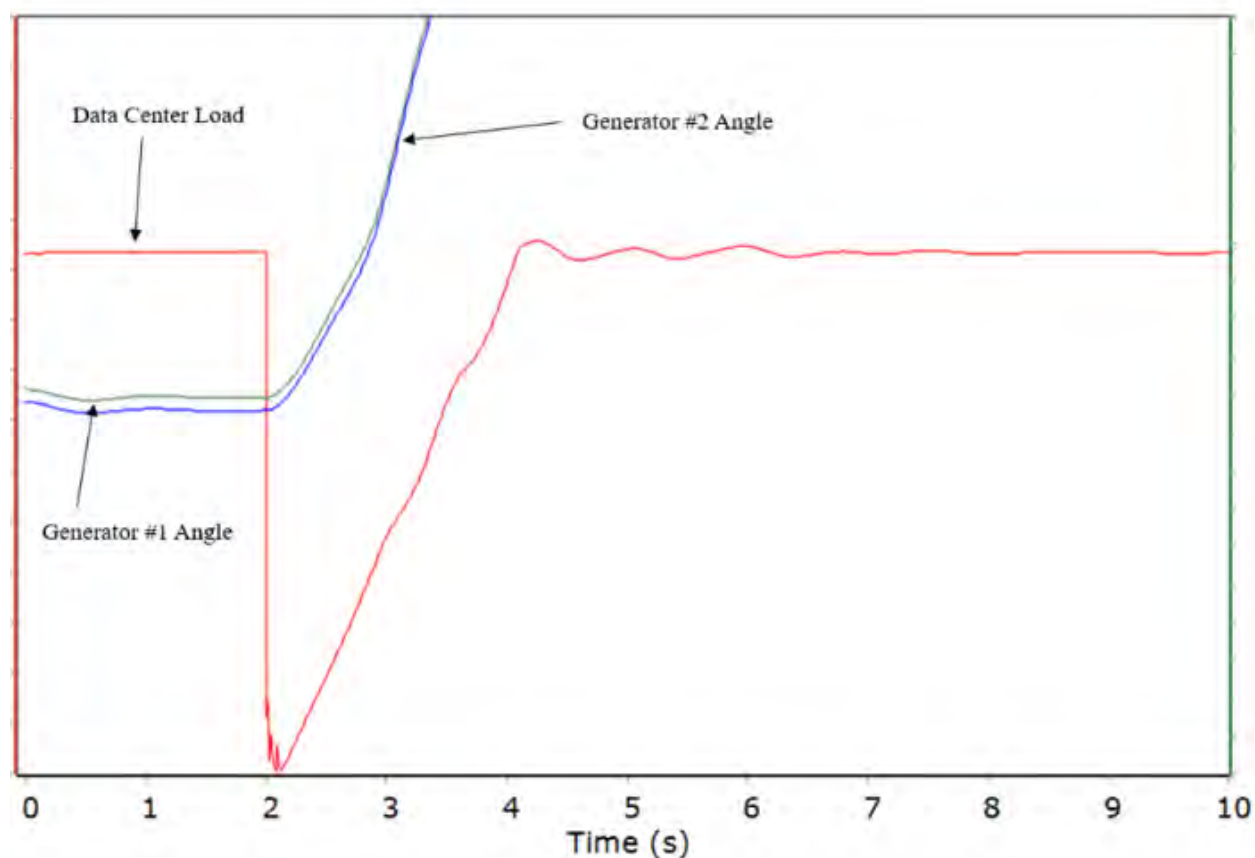


Figure 5.1: Multiple Generators Lose Synchronism Following a Data Center Load Trip and Subsequent Rapid Recovery

TOs and PCs should consider angular stability risks when evaluating large loads in areas with long radial lines or high impedance corridors or during scenarios involving delayed fault clearing. EMT or RMS simulation models should represent the fast dynamics of load components, including converter controls, UPS synchronization, and backup generation transitions. This is necessary to assess system response to disturbances. For large load centers, planners should study the impact of large load trip or recovery during N-1 and N-1-1 contingencies, especially in low-inertia regions. This helps determine the risk of angular separation or uncontrolled power swings.

Event analysis post-fault should examine angle trajectories and coherency groups to determine if large load behavior was a contributing factor to any loss of synchronism or instability. TOs and PCs should utilize real-time monitoring to monitor for angular stability risks. TOs and TPs should update modeling assumptions accordingly based on system changes and identified control or stability issues.

Chapter 6: Power Quality

Emerging large loads often contain significant quantities of electronic power supplies, adjustable speed drives, and rectifiers, which can generate harmonic distortion and voltage fluctuations in the BPS. TPs should perform studies using the as-designed models provided by the large loads to identify power quality impacts and ensure that they are within the acceptable levels or if any mitigation measures will be necessary. Studies should be conducted under the diverse operating modes of large loads while also considering various potential load equipment configurations.

Harmonics

When considering harmonics, power quality standards (e.g., IEEE Standard 519-2022) already exist that specify harmonic limits with which all large loads are recommended to follow. Since existing power quality standards are not mandatory, TOs or DPs should include harmonic limits in their interconnection requirements for large loads, as well as any RC, BA, or TOP requirements specific to their footprint, into their interconnection requirements under FAC-001.

Using the data provided by the large load, the TP and PC should use as-designed models to ensure that individual and overall current harmonics injections into the interconnecting substation are within the limits.

During the power quality studies, harmonic evaluation studies may be performed by the TP and/or PC to do the following:

- Determine the impact of large load-produced harmonic current injections on electrically close synchronous generators and other equipment to ensure that the levels are within the specified equipment ratings (i.e., permissible continuous equivalent negative-sequence current capability)
- Consider evaluating risks of harmonic resonance and determine the potential impact of large load-produced harmonic current injections on existing harmonic filter banks (i.e., impact of harmonics on individual filter component ratings)
- Determine the impact of large load-produced harmonic current injections on the overall voltage distortion at the interconnecting substation
- Determine the harmonic spectrum of the large load under various grid conditions, including low short-circuit ratio (SCR) scenarios
- Determine if mitigation measures will be necessary to meet the machine or harmonic filter ratings. In cases where technical solutions are insufficient for meeting harmonic limits, alternative approaches like utility-scale battery storage may be needed

To support the analyses above, load owners should provide the current harmonic spectra to the TP enabling estimation of the individual harmonic current injections (up to 100th harmonic order)⁴⁵ at the interconnecting substation.

Managing Facility Design Changes that Impact Power Quality

The harmonic emissions and voltage fluctuations associated with a particular large load may vary significantly with design decisions that may not be made until the interconnection process is well underway (e.g., the selection of specific vendors for electronic devices or determination of the site's mix of computational processes). In such cases, the load facility design changes may impact the load facilities' compliance with power quality requirements. TOs and DPs should have a clear process on how and when large load facility design changes are communicated to them by the large load entity. In these situations, the

⁴⁵ The 100th harmonic order is provided as example guidance, and entities may modify this for their own applications.

large load entity may experience cost increases and schedule delays if TO and DP processes are unclear on how design changes are communicated and handled. If design changes result in 10% or more increase in projected harmonic emissions,⁴⁶ interconnection studies should be re-performed.

Even after a large load is put into service, significant changes in its load profile (e.g., switching from traditional cloud services to large-language model training) could result in power quality violations that may not have been identified in earlier studies. It may then become necessary to specify and install additional equipment (e.g., harmonic filters or active power conditioning devices) to mitigate the violation, incurring additional costs and potentially altering the interconnection timeline.

TOs and DPs should have clear policies in place to handle such scenarios along with the appropriate measures that may be taken to ensure system reliability (e.g., operational restrictions or other mitigations). Additionally, based on the severity of the violation, timelines for remediation could be determined without immediately impacting the operational status of the project (e.g., a minor violation may be permitted to continue without operational downtime for the project so long as it is resolved within a reasonable amount of time).

TOs and DPs should have policies for addressing unanticipated power quality impacts that are not covered by limits set forth in interconnection agreements. For example, it is possible that demand fluctuations at a large load may cause the lights of other nearby customers to flicker, even if the load owner is subjected to and compliant with relatively strict interharmonic limits. There is also the possibility of unforeseen interactions between equipment at multiple large load facilities or IBRs that are electrically close to one another. TOs and DPs should have policies in place that enable cooperation with load owners to resolve these issues.

Power Quality Monitoring and Analysis

TOs should install high-resolution data monitoring equipment at the point of interconnection substation to collect operational power quality measurements. This data can be used to validate the accuracy of expected power quality performance (e.g., load profile), compliance with power quality performance limits, and whether the large load is participating in system power quality issues. In the event of system-level power quality impacts, TPs and PCs should use the validated as-left load models to perform power quality studies to mitigate any identified deficiencies and propose solutions.

⁴⁶ Here, 10% is provided as an example criteria, and entities may choose to implement a different value for their criteria.

Chapter 7: Physical and Cyber Security

This chapter provides recommendations for NERC registered entities and large load entities to systematically integrate physical and cyber security considerations into the planning, design, and integration processes for new or existing large industrial loads. The objective is to ensure that the integration of such large load facilities maintains or enhances the reliability, resilience, and security of the electric grid, consistent with NERC Reliability Standards and good utility practice. This chapter is informed by the initial work of the NERC LLWG as documented in its white papers, *Characteristics and Risks of Emerging Large Loads* and *Assessment of Gaps in Existing Practices, Requirements and Reliability Standards for Emerging Large Loads*. It emphasizes proactive risk mitigation for both physical and cyber threats, recognizing the potential impact of large load facilities on regional and interconnected system stability.

Holistic Risk Assessment

NERC registered entities and large load entities should conduct comprehensive, forward-looking risk assessments that integrate physical and cyber threat vectors impacting both the large load facility itself and its point of interconnection with the BPS. This assessment should consider the potential for cascading impacts on the wider grid. The assessment should also account for the unique operational characteristics and potential vulnerabilities of diverse large loads, including data centers and industrial facilities with BTM power generation and storage resources, as well as demand-side management capabilities. The results of this assessment should be used to inform potential mitigating actions needed.

Security-by-Design

NERC registered entities and large load entities should advocate for and require the incorporation of physical and cyber security controls as foundational elements during the design phase of new large load interconnections rather than as retrofitted additions. This approach should address new cyber attack vectors introduced by the growing adoption of internet-connected process control networks (PCN), operations management networks (OMN), and industrial control systems (ICS) and the potential for these loads to participate in energy markets as aggregated distributed energy resources.

Operational Interdependency Recognition

NERC registered entities and large load asset owners should acknowledge and plan for the operational interdependencies between the large load's internal systems (e.g., industrial control systems, microgrid controls) and the utility's BES control systems, ensuring secure and reliable data exchange and control capabilities.

Collaboration and Information Sharing

NERC registered entities and large load asset owners should foster effective communication and collaboration from the earliest stages of a project. This collaboration is crucial for identifying, assessing, and effectively mitigating evolving security challenges and may necessitate updates to existing NERC Reliability Standards and the development of new best practices. The interconnection agreement and applicable tariffs serve as the primary legal and contractual mechanisms to formally define the terms of this collaboration and information sharing.

Physical Security Considerations for Large Load Interconnection

Site Selection and Layout Review (CIP-014 Alignment)

- **Purpose:** To identify and mitigate physical security risks associated with the location and configuration of large load facilities and their immediate interconnection infrastructure.

- **Guideline:** NERC registered entities and large load asset owners should perform an initial assessment of the potential criticality of the proposed interconnection substation and associated transmission elements if subjected to physical attack (aligned with CIP-014 principles). The physical environment, accessibility, and visibility of the proposed site should be analyzed, and design features that inherently enhance physical security should be recommended. This includes advising on robust perimeter security for critical components. Entities may also consider incorporating geospatial risk analysis, considering proximity to urban areas, transportation hubs, or known threat sources.

Equipment Protection and Resilience

- **Purpose:** To ensure that critical equipment supporting the large load interconnection is adequately protected against physical threats and can withstand or recover from attacks.
- **Guideline:** Recommend hardening measures for critical control houses, communication infrastructure, and vulnerable equipment for large load assets. This includes physical security for control cabinets or converter stations for devices like STATCOM/FACTS/BESS/HVdc converters as well as adequate physical hardening of substations where these devices are installed. Opportunities for redundant physical pathways or diverse equipment routing should be explored to minimize single points of failure. Both NERC registered entities and large load asset owners should also coordinate on strategies for rapid replacement of critical long lead-time equipment.

Detection, Surveillance, and Response Integration

- **Purpose:** To ensure that physical security measures at the large load's interconnection point are integrated into broader utility security operations.
- **Guideline:** NERC registered entities and large load asset owners should implement and integrate surveillance (like closed-circuit television), intrusion detection systems, and access control systems. This should address the lack of physical security measures for critical OT components like remote terminal unit, PMUs, static VAR compensator control houses, BESS containers, HVdc converter stations, and communication nodes. Joint discussions and planning between the large load entity, the interconnecting utility, and local law enforcement/first responders should be facilitated for unified response to physical security incidents. Surveillance systems should feed into the utility's security operations center for real-time monitoring and response coordination.

Cyber Security Considerations for Large Load Interconnections

Secure Network Design and Architecture (CIP-005, CIP-007 Alignment)

- **Purpose:** To ensure that the network architecture supporting the large load interconnection is designed to prevent, detect, and respond to cyber incidents.
- **Guideline:** NERC registered entities and large load asset owners should mandate robust network segmentation between the large load's operational technology and IT networks. They should require the use of encrypted and authenticated communication protocols for all data exchange. They should also establish strict controls and secure methods for any remote access to critical systems at the large load facility that could impact the BPS.

Supply Chain Risk Management (CIP-013 Alignment)

- **Purpose:** To mitigate cyber security risks introduced through the supply chain of equipment and software utilized in the large load interconnection.

- **Guideline:** Large load asset owners should conduct cyber security due diligence on vendors providing control systems, network devices, and critical software for their interconnection.

Vulnerability Management and Patching (CIP-007 Alignment)

- **Purpose:** To ensure ongoing management of vulnerabilities in systems related to the large load interconnection.
- **Guideline:** Large load asset owners should perform regular vulnerability assessments and penetration testing for critical systems within the large load's operational environment that interface with the BPS. They should also establish protocols for coordinating patching and security updates.

Incident Response and Recovery Planning (CIP-008 Alignment)

- **Purpose:** To ensure the capability to detect, respond to, and recover from cyber security incidents impacting the large load interconnection.
- **Guideline:** NERC registered entities and large load asset owners should facilitate the development of joint cyber security incident response plans. They should also emphasize robust data backup and system restoration capabilities for critical systems at the large load facility that impact BES reliability. The interconnection agreement should include a jointly developed and tested incident response plan with clear communication protocols, roles, and responsibilities. Large load asset owners could encourage staff participation in E-ISAC GridEx exercises.⁴⁷

Documentation, Review, and Continuous Improvement

Documentation Requirements: All analyses, recommendations, and agreements stemming from the physical and cyber security assessments should be thoroughly documented.

Review and Update Cycle: This guideline and its application should be reviewed periodically to ensure continued relevance and effectiveness. Any updates to the security posture should be formally amended into the interconnection agreement. Large load entities should conduct annual security posture reviews, aligning with NERC audit cycles, and amend agreements as needed.

Training and Awareness: Large load entities should regularly train their personnel on the importance of physical and cyber security. This should address the critical gap regarding personnel security and training for large loads.

⁴⁷ E-ISAC's GridEx exercises are comprehensive, large-scale, biennial events that simulate coordinated cyber and physical attacks on North America's electric grid to test and improve crisis response and resilience.

Chapter 8: Resilience, System Restoration, and Load Shedding

In a 2018 report, NERC's Reliability Issues Steering Committee created a resilience framework that focuses on four outcome-based abilities of resilience: robustness, resourcefulness, rapid recovery, and adaptability.⁴⁸ Resilience is similarly defined by the NATF and EPRI as "the ability of the system and its components (both equipment and human) to 1) prepare for, 2) anticipate, 3) absorb, 4) adapt to, and 5) recover from non-routine disruptions, including high impact-low frequency (HILF) events, in a reasonable amount of time...".⁴⁹ Typical Bulk Electric System (BES) resilience infrastructure facilities include manual load shedding, automatic load shedding, and system restoration.

Large loads, with their high power ratings and dynamic characteristics, can introduce challenges to BES resilience. This chapter analyzes reliability risks posed by large loads, identifies key gaps, and proposes mitigation measures to enhance BES resilience.

Load Shedding

Manual Load Shedding

NERC EOP-011 requires BAs and TOPs to have the capability and provisions to implement manual load shedding (MLS) to mitigate emergencies. Additionally, it mandates provisions to minimize the overlap among circuits designated for MLS, UVLS, and UFLS. In areas with a high penetration of large loads, avoiding overlap among these programs may be difficult if large loads are excluded from participation. Therefore, TOs should consult with BAs and TOPs to determine whether including large loads in MLS plans is appropriate. Additionally, BAs and TOPs, in coordination with TOs, should consider whether it is appropriate to implement dynamic MLS using real-time SCADA to adjust shed amounts based on current load profiles.

Given that the load profile of large loads may be conforming or non-conforming to the aggregate system load profile, shedding them based on the UFLS prediction could result in failing to meet the load-shedding obligation or shedding too much load, leading to overfrequency and/or overvoltage situations.

The following recommendations aim to address these issues:

- **Monitor Actual Load Consumption:** Real-time monitoring, such as SCADA or telemetry, is critical for TOPs to accurately control the amount of load shed. Large loads participating in MLS should be equipped with such monitoring systems.
- **Partial Load Shedding:** Segmenting a large load into controllable blocks allows for more precise load shedding while maintaining service to other parts. TOPs and RCs should develop guidelines and standards for partial load shedding of large loads in coordination with large load entities.
- **Consider co-located and BTM configurations:** TOPs and RCs should consider the effect of any co-located or BTM generation when designing and executing load shed plans.
- **Incorporate Data Center Flexibility:** Some data centers have flexibility to rapidly change their demand by rescheduling or shifting machine learning workloads and non-urgent compute tasks to

⁴⁸ NERC, *Reliability Issues Steering Committee - Report on Resilience*, November 2018. https://www.nerc.com/globalassets/who-we-are/standing-committees/risc/risc-resilience-report_approved_risc_committee_november_8_2018_board_accepted.pdf

⁴⁹ NATF and EPRI, *Understanding the Definition of Resilience (Companion Document)*, November 2025. [https://www.natf.net/docs/natfnetlibraries/documents/resources/resiliency/understanding-the-definition-of-resilience-\(companion-document\).pdf](https://www.natf.net/docs/natfnetlibraries/documents/resources/resiliency/understanding-the-definition-of-resilience-(companion-document).pdf)

support the grid.⁵⁰ Agreements and protocols can be set up between TOPs and large load entities on integrating these flexibilities to support the grid when necessary.

- **Coordination with Load Owners:** TOs/TOPs and large load entities should establish communication pathways to coordinate expected load shedding needs.
- **Regular Obligation Review:** RCs and TOs should increase the frequency of reviewing load shedding obligations to keep pace with large load growth.

Automatic Load Shedding

NERC PRC-006 defines design and documentation requirements for automatic UFLS programs. The aim of these programs is to balance system load with available generation sources in the event of a system-wide incident that causes a shortage of available generation to meet the connected load. Due to the size of large loads ranging from tens to thousands of megawatts, as well as the high penetration of multiple large loads in a given PC area, it may be necessary to include large loads as part of UFLS schemes to satisfy the PRC-006 performance criteria. Large loads may cause significant load growth in some areas, which causes the relative percentage of UFLS load to be reduced to below 25%. Therefore, TOs should coordinate with PCs and use studies to determine if it is appropriate to include the large loads in their UFLS programs (e.g., TOs and PCs may require large loads to design and operate facilities to have the capability to participate in automatic UFLS or in distribution management system (DMS) control, in accordance with relevant standards like PRC-006). Large load entities should provide, and TOs should collect, all necessary information about facility protections and transfer schemes that may impact UFLS, UVLS, or MLS programs. Finally, responsibilities should be clearly defined for design, control, and operation of necessary equipment for UFLS, UVLS, and MLS and coordinated between the large load entity, TO, TOP, and other relevant parties.

PRC-006 requires the frequency of each identified island to remain within the defined range for underfrequency conditions resulting from an imbalance of up to 25%. The departure of actual UFLS stage percentages from obligation percentages at any time could result in insufficient or excessive UFLS capability available from PRC-006 design basis of 25%.⁵¹ For a UFLS program originally established to include at least 25% of the total load, when one or more non-UFLS participating large load(s) are added to the total load, the original stationary UFLS percentage may not sustain and may need to change depending on if the large load is on-line or off-line and if the other loads are at peak or minimum demand. Keeping the original static UFLS percentage could cause insufficient or excessive UFLS and may result in the frequency excursion.

The recommendations include the following:

- **Improved Observability:** TO, TOP, DP and other UFLS entities should monitor real-time changes in UFLS load percentage.
- **Set Load Variability Bounds:** PCs should define acceptable load variability ranges.
- **Coordinate Across Areas:** BAs should coordinate to synchronize UFLS staging between exporting and importing areas, which can reduce transmission stress.
- **Coordinate with Large Load Protection and Control Settings:** Large loads are sensitive to system frequency/voltage changes and can automatically switch to internal backup generation (equivalent to large load shedding for the grid) when large frequency/voltage deviations are observed at their

⁵⁰ Google, *How we're making data centers more flexible to benefit power grids*, August 2025. <https://blog.google/inside-google/infrastructure/how-were-making-data-centers-more-flexible-to-benefit-power-grids/>

⁵¹ R. O'Keefe, *Proposed PRC-006 SAR for UFLS Variability Monitoring and Stage Percent Bounds*, presented at the Large Loads Task Force Meeting, June 2025. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_june_workshop_presentations.pdf

terminals. Thus, TOs and BAs should consider such behaviors in their UFLS settings and program design.

- **Partial Load Shedding:** Segmenting a large load into controllable blocks allows for more precise load shedding while maintaining service to other parts. TOPs and BAs should consider partial load shedding of large loads in coordination with large load entities where feasible.

Similarly, NERC PRC-010 establishes an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS programs. In some cases, large loads may be of significant size or clustered in an area where inclusion of large loads as part of UVLS schemes is needed to satisfy the PRC-010 performance criteria. Therefore, TOs should coordinate with PCs to determine if it is appropriate to include the large loads in their UVLS programs.

Both PRC-006 and PRC-010 require each PC or TP to evaluate the effectiveness of each UFLS and UVLS program at least every five years. Given that large loads can be constructed in as quickly as 12 –18 months and due to rapid large load deployments, an assessment every five years may not be sufficient. PCs and TPs should dynamically adjust the UFLS and UVLS assessment frequency based on the load growth rate of their system or define a system load deployment threshold that triggers new UFLS or UVLS assessments if the threshold is passed. This will ensure UFLS and UVLS reliability in areas with fast load growth. If new assessments are not performed, then the BPS may collapse if UFLS or UVLS schemes are triggered but prove inadequate due to load growth.

If a TO determines that a large load is part of its MLS, UVLS, or UFLS schemes,⁵² the TO should require the large load to coordinate with the testing, maintenance, and design scheme (e.g., feeder breaker tripping) to support implementation.

Additionally, due to the voltage sensitivity of some types of large loads and the potential for simultaneous disconnection during a single fault or disturbance due to collective ride-through behavior, TP and PCs should also assess frequency stability, including overfrequency performance, the need for overfrequency protection schemes, and the MSSC on the demand side. TPs should require large load entities to submit the ride-through capability data of the load and the test report including the as-built ride-through characteristics, which should be modeled and considered in the planning and operational analyses.

Dynamic Load Shed Monitoring and Allocation

If large loads are included in load shed plans such as MLS, UVLS, or UFLS, then TOs and DPs should coordinate on a real-time basis if dynamic computation of load shed allocation is implemented. TOs and DPs should develop communication protocols to automatically communicate load shed percentages in real time to protection systems in the field. TOs should assess the need for a wide-area measurement system (WAMS) and a wide-area protection scheme that dynamically sets and adjusts load shed allocations for both manual load shed and automatic load shed functions.

⁵² There is a DP-UFLS registered entity according to NERC ROP Appendix 5B: A Distribution Provider entity shall be an Underfrequency Load Shedding (UFLS)-Only Distribution Provider if it is the responsible entity that owns, controls or operates UFLS Protection System(s) needed to implement a required UFLS program designed for the protection of the BES, but does not meet any of the other registration criteria for a Distribution Provider. A DP designated as 'DP – UFLS Only' will only be accountable for a sub-set of the NERC Reliability Standards as described in Section III.b.2 of NERC ROP Appendix 5B, Statement of Compliance Registry Criteria.

System Restoration

System operators maintain blackstart procedures to restore the grid following widespread outages. The integration of large loads challenges traditional assumptions due to their scale and flexibility and the fact that load operators may not have previously interacted with system operators. These procedures should be updated accordingly to ensure that TOPs can reliably blackstart the grid with large loads.

Load Coordination

While load restoration is a crucial element of blackstart, large loads specifically are unlikely to be restored in early stages of blackstart unless they play a critical role in BPS reliability (e.g., gas compressor stations). During system restoration, TOPs, BAs, and RCs must match load pickup with generation availability and keep load constant and controlled. Uncontrolled load pickup creates large voltage and frequency swings that can negatively impact the stability of blackstart islands and potentially collapse the island. In the past, the TOP would work with the DP to operate distribution equipment (e.g., breakers and switches) to energize load and the load behavior could primarily be safely assumed. With large loads, a single load may be selected for priority restoration and may energize in stages in coordination with the load operator. To accomplish this, the TOP and large load entity should establish communication paths to coordinate during system restoration. Without a communication path, the load cannot be adequately managed for reliable use in blackstart procedures.

While TOPs and RCs have traditionally considered the impact of cold load pickup, large loads may exhibit new variations. If large loads are restored early on, they pose a risk to the blackstart island stability as the stability of the island is sensitive to changes in frequency and voltage. To mitigate this, the TOP, BA, and RC should establish limits for load variability and blackstart island load ramping in the islands and along the cranking paths and review the priority of large loads in their restoration plans.

Modeling and Simulation for Restoration Studies

To perform accurate studies for selecting blackstart units and cranking paths, it is important for the system operator to obtain information about the load it intends to pick up early in the system restoration process. The TOs, BAs, and RCs should gather the data mentioned in [Chapter 1](#) and reflect them in the model used for system restoration analysis.

Without this information to build the precise model, the system operator is limited in its ability to perform accurate blackstart analyses or create reliable restoration plans.

Given the growing dynamics and uncertainties with these large load behaviors, TOPs should perform detailed restoration studies using transient stability and/or electromagnetic transient simulation tools with appropriate or best-known load models to verify the effectiveness of the restoration plans regularly and adjust their plans to mitigate potential issues.

Chapter 9: Conclusion

In summary, large loads are being integrated faster than ever and at a scale never before seen. New processes will be needed, and existing processes should be updated to mitigate risks to the BPS from large loads. Although the RSTC Charter requires a review for continued applicability at least every three years for reliability guidelines, with recent large load growth, this reliability guideline may require more frequent reviews as needed (particularly as NERC is working with stakeholders on updates to registry criteria and Reliability Standards to account for large load integration).

Data collection and sharing are foundational to ensuring that accurate assessments can be performed by NERC registered entities. Similar to recent strides in model quality for IBRs, large loads require comprehensive model verification and model validation processes to ensure accurate modeling and reliable operations. This will require strong, ongoing coordination between OEMs, large load entities, and existing NERC registered entities. This also requires dynamic modeling to be accounted for in the earliest stages of design, as opposed to an afterthought once the facility design is complete.

DPs and TOs, in coordination with TP and PCs, are responsible for creating and enforcing interconnection requirements that account for local and system-wide reliability-enhancing processes, including modeling, coordination, analysis, performance, and real-time monitoring. Additionally, new risks and failure modes require TP and PCs to update their interconnection and planning study processes to ensure that key risks are analyzed and mitigated.

New challenges are being introduced to grid operators, and increased coordination along with new operational requirements can mitigate those challenges. Grid operators will need new data to inform processes that ensure reliable operations, like receiving real-time telemetry and near-term forecasts from large load entities. Additionally, BAs and RCs will need to plan for increased non-conforming variable loads in real-time operations.

Stability risks are clearly demonstrated in prior incident reviews and other analyses. Some of the stability risks mentioned in [Chapter 5](#) can lead to instability, cascading, and uncontrolled separation before operators even have a chance to intervene. Improved data collection, post-event analysis, and dynamic planning studies will be required to prevent critical risks in the stability domain.

Power quality, while currently deemed a lower-likelihood risk, should be accounted for, monitored, and analyzed.

Physical and cyber security, similar to dynamic modeling, should be integrated into facility design at an early stage and coordinated with relevant NERC registered entities.

Finally, load shedding and system restoration risks require consideration at early stages of large load facility design. These risks also require new analysis and coordination from existing NERC registered entities.

Appendix A: High-Level Recommendations

Category	Recommendation	LLE	DP	TO	TP	PC	TOP	BA	RC
Data Collection and Modeling	Provide steady-state, dynamic, and other data	P	L	L	SR	SR			
	Install high-speed FR, DDR, and SER	L	C	C					
	Provide high-speed recording data for post-event analysis	P	C	C	C	C	SR	SR	SR
	Provide updates to modeling data (as-built)	P	L	L	SR	SR			
	Provide real-time electrical measurements	P		P			SR	SR	SR
	Provide near-term demand forecasts	P		C				SR	SR
	Perform model quality assessment, model verification, model validation	L			SR	SR			
Interconnection	Collect data and share with relevant entities	C	L	L	SR	SR	SR	SR	SR
	Study reliability impacts of new large load	C	C	C	L	L	M	M	M
	Periodic near-term studies for collective impact of new large loads	C	C	C	L	L	M	M	M
	Comprehensive commissioning process for large loads	C	C	C	C	C	SR	SR	SR
	Develop EMT screening criteria where needed	M	C	C	SR	SR			M
Long-Term Planning	Study reliability impacts of new large load	C	C	C	L	L	M	M	M
	Resource adequacy analysis considering unique risks of large loads	C	C	C					
Operations and Balancing	Verify communications (phone communications, telemetry, etc.)	C					SR	SR	SR
	Integrate into operational systems (forecasting, outages, day-ahead studies)	C					SR	SR	SR
	Conduct commissioning tests of the large load	C		C			SR	SR	SR
	Post-commissioning testing and verification	C					SR	SR	SR
	Provide real-time electrical measurements	P		P			SR	SR	SR
	Provide near-term demand forecasts	P		C				SR	SR
	Specify data requirements for large loads real-time analysis and monitoring	C					SR	SR	SR
	Prepare for largest expected load contingency (CILR, ramping, or other)	C			C	C		SR	SR
	Minimize variability via large load facility software mitigations	L						SR	SR
	Respond to operating instructions	L					SR	SR	SR
	Event analysis	C			L	L	L	L	L
Stability	Define disturbance performance criteria based on studies	C	C	C	C	SR	C	C	SR
	Study and mitigate risks from CILR events	C	C	C	L	L	M	L	L
	Design and operate facilities to follow disturbance performance criteria	L	C	C	SR	SR	C	C	SR
	Study, mitigate, and monitor oscillations from large loads	C	M	L	L	L	C	M	SR
Power Quality	Study, mitigate, and monitor power quality risks from large loads	C	M	L	L	C	C		C
Physical and Cyber Security	Holistic risk assessment	L							
	Implement security-by-design practices	L							
	Study and plan for operational interdependency between utility and large loads	C	C	C	C	C	C	C	L
	Implement physical security considerations	L							
	Implement cyber security considerations	L							
Resilience	Monitor any large loads involved in manual load shed, UFLS, and UVLS	C	C	C			L	L	
	Consider integration of large loads into UFLS and UVLS schemes	C	L	L			L	L	

C = Coordinate

L = Lead

M = Monitor

P = Provide

SR = Specify Requirements

Appendix B: Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline.

Name	Entity
Shahrokh Akhlaghi	Ulteig Engineers, Inc.
Dlzar Al kez	The University of Manchester
Margaret Albright	Bonneville Power Administration (BPA)
Kunal Amare	Dominion Energy
Rahul Anilkumar	Quanta Technology
Jack Armstrong	Duke Energy
Abolfazl Babaei	RMS Energy
Shuchi Biswas	Pacific Northwest National Laboratory (PNNL)
Julie Booth	North American Electric Reliability Corporation (NERC)
James Briones	Department of Energy (DOE)
Sharon Brown	Public Service Electric and Gas Company (PSE&G)
Alexander Carlson	North American Electric Reliability Corporation (NERC)
Candice Castaneda	North American Electric Reliability Corporation (NERC)
Arber Caushaj	New York Independent System Operator (NYISO)
Will Chung	Iron Mountain
Jose Conto	Electric Reliability Council of Texas (ERCOT)
Amin Dadashzade	Zero-Emission Grid LLC
Patrick Dalton	Midcontinent Independent System Operator (MISO)
Suman Debnath	Oak Ridge National Laboratory (ORNL)
Mike Della Penna	Google
Hasala Dharmawardena	North American Electric Reliability Corporation (NERC)
Raj Reddy Dontireddy	New York Independent System Operator (NYISO)
Douglas Eakins	Exelon
Beth Eurich	Midcontinent Independent System Operator (MISO)
Armando Figueroa Acevedo	Midcontinent Independent System Operator (MISO)
Jack Gibfried	North American Electric Reliability Corporation (NERC)
Jigar Gorasiya	Energynx LLC
Alexandra Gorin	Rocky Mountain Institute (RMI)
Venona Greaff	Oxy
Sam Holeman	Duke Energy
James Huang	Enchanted Rock
Qihua Huang	Colorado School of Mines
Laura Hussey	GDS Associates
Marilyn Jayachandran	Electric Reliability Council of Texas (ERCOT)
Weiqing Jiang	Midcontinent Independent System Operator (MISO)
Alex Kloiber	Central Iowa Power Cooperative (CIPCO)
Anupama Konara	Manitoba Hydro

Name	Entity
Radha Krishna Moorthy	Oak Ridge National Laboratory (ORNL)
Douglas Ladd	Dominion Energy
Kate Lamb	Electric Reliability Council of Texas (ERCOT)
Beibei Li	Midcontinent Independent System Operator (MISO)
Chenxi Lin	Jacobs Engineering Group
Priya Mana	Pacific Northwest National Laboratory (PNNL)
Sudip Manandhar	Southern Company (SOCO)
Julia Matevosyan	Energy Systems Integration Group (ESIG)
Sharon Mayers	American Municipal Power (AMP)
Eric Meier	Electric Reliability Council of Texas (ERCOT)
Evan Mickelson	North American Electric Reliability Corporation (NERC)
Parag Mitra	Electric Power Research Institute (EPRI)
Nihal Mohan	Nextera Energy Transmission LLC
Saurav Mohapatra	PowerWorld Corporation
Julia Morgan	Idaho National Laboratory (INL)
Jasmine Morris	Southern Maryland Electric Cooperative (SMECO)
Josh Murphy	SERC Reliability Corporation
Michael Nix	Duke Energy
James Okullo	Energy Systems Integration Group (ESIG)
Nima Omran	Independent Electricity System Operator (IESO)
Palak Parikh	GE Vernova
Miguel Perez	New Mexico Public Regulation Commission
Maryclaire Peterson	Entergy
Evan Pierce	EdgeConneX
Chris Postma	POWER Engineers, Inc.
Maya Prica	Department of Energy (DOE), National Energy Technology Laboratory
Qun Qiu	American Electric Power (AEP)
Mohamed Ramadan Younis	Electric Power Engineers (EPE), Inc.
Ahmed Rashwan	Electric Power Engineers (EPE), Inc.
Mark Reeves	Georgia System Operations Corporation (GSOC)
Rachel Reichenberger	Idaho National Laboratory (INL)
Rouzbeh Reza Ahrabi	Electric Power Engineers (EPE), Inc.
Benjamin Rodriguez	El Paso Electric Company
Preethi Rondla	California Independent System Operator (CAISO)
Brett Ross	Pacific Northwest National Laboratory (PNNL)
Dominic Scarpignato	Scarp Industries Corp.
Mostafa Sedighzadeh	Southwest Power Pool (SPP)
Mohamed Shamseldein	Independent Electricity System Operator (IESO)
Kat Sico	Duke Energy
Iknoor Singh	Midcontinent Independent System Operator (MISO)

Name	Entity
Julie Snitman	Electric Reliability Council of Texas (ERCOT)
Agee Springer	Electric Reliability Council of Texas (ERCOT)
Kannan Sreenivasachar	Independent System Operator New England (ISO-NE)
Nathan Strobel	North American Electric Reliability Corporation (NERC)
Robert Stroh	Constellation Energy
Shilpi Sunil Kumar	MARA
Khundmir Syed	Diode Ventures, LLC (Black & Veatch)
Adam Taylor	SERC Reliability Corporation
Ethan Tellier	Central Iowa Power Cooperative (CIPCO)
Daniel Vergara	Clearway Energy
Matthew Wharton	PJM
Chris White	GDS Associates, Inc.
Sesha Yeruva	Siemens Industry Inc.
Roberto Zanchi	Rocky Mountain Institute (RMI)
Jiecheng Zhao	Elevate Energy Consulting

Appendix C: Guideline Information and Revision History

Guideline Information	
Category/Topic: [NERC use only]	Reliability Guideline/Security Guideline/Hybrid: Reliability Guideline
Identification Number: [NERC use only]	Subgroup: Large Loads Working Group

Revision History		
Version	Comments	Approval Date
1.0		April 30, 2026

Appendix D: Metrics

Pursuant to the Commission's Order on January 19, 2021, North American Electric Reliability Corporation, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- [Insert metrics specific to the content of this reliability guideline here]

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- Industry survey on effectiveness of Reliability Guidelines;
- Triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

[Guideline Effectiveness Survey](#)