June 21, 2021

VIA ELECTRONIC FILING
Adam Teitzman, Commission Clerk
Division of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Re: Docket No. 20210015-EI
Petition by FPL for Bate Rate Increase and Rate Unification

Dear Mr. Teitzman:

Attached for filing on behalf of the CLEO Institute and Vote Solar in the above-referenced docket are the testimony and exhibits of Curt Volkmann.

Thank you for your assistance in this matter. Please let me know if you should have questions regarding this submission.

Sincerely,

Katie Chiles Ottenweller
Attorney for Vote Solar
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Atlanta, GA 30307
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CERTIFICATE OF SERVICE
Docket No. 20210015-EI

I HEREBY CERTIFY that a true and correct copy of the testimony and exhibits of Curt Volkmann filed on behalf of The CLEO Institute and Vote Solar have been furnished by electronic mail on this 21st day of June, 2021, to the following:

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/s/ ***Katie Chiles Ottenweller***

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power and Light Company	**DOCKET NO. 20210015-EI**

DIRECT TESTIMONY OF
CURT VOLKMANN

ON BEHALF OF

THE CLEO INSTITUTE
AND
VOTE SOLAR

June 21, 2021

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 132 Lake Vista Circle, Fontana, Wisconsin, 53125.

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

A. I am testifying on behalf of Vote Solar and The CLEO Institute Inc. (collectively "VS-CLEO").

Q. By whom are you employed and in what capacity?

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with clients in a variety of general rate case, grid modernization, and distribution planning regulatory proceedings.

Q. Please summarize your education and professional experience.

A. I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 36 years of experience in the utilities industry, primarily in electric transmission and distribution. My work experience includes nine years at Pacific Gas & Electric in various transmission and distribution ("T&D") engineering roles and eighteen years at Accenture with several positions including Executive Director in the North American Utilities practice. Since 2015, I have worked independently and supported clients in T&D-related regulatory proceedings in several states. Exhibit CV-1 provides a statement of my qualifications and experience.

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. No.

Q. Have you previously testified before other regulatory commissions?

A. Yes. In the past six years, I have testified and commented before regulatory commissions in Arizona, Arkansas, California, Iowa, Illinois, Massachusetts, Michigan, Minnesota, New York, Ohio, Utah, and Virginia. Exhibit CV-2 provides a summary of my prior testimony and contributions to comments.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit CV-1: Curt Volkmann's Statement of Qualifications and Experience
- Exhibit CV-2: Prior Testimony and Contributions to Comments by Curt Volkmann
- Exhibit CV-3: Compiled responses to Interrogatories and Production of Documents requests
- Exhibit CV-4: Potential Metrics for T&D Capital Performance Management
- Exhibit CV-5: ICE Calculator screenshots
- Exhibit CV-6: Grid Modernization Playbook
- Exhibit CV-7: Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations
- Exhibit CV-8: Cited Portions of FPL Witness Michael Spoor's deposition dated June 16, 2021

II. PURPOSE OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. My testimony summarizes my assessment of a subset of the proposed T&D capital expenditures by Florida Power & Light Company ("FPL") and Gulf Power ("Gulf", collectively "FPL-Gulf" or "Company") as described in the Company's direct testimony of witness Michael Spoor. Specifically, I focus on the proposed T&D capital expenditures for Reliability/Grid Modernization and Growth.

Q. Please summarize your conclusions.

A. I conclude that the Company's proposed $11.5 billion of Reliability/Grid Modernization and Growth capital expenditures in 2019-2023 are unsupported with evidence in the record.

Q. Did VS-CLEO attempt to collect evidence in support of the Company's proposed $11.5 billion T&D Reliability/Grid Modernization and Growth capital expenditures?

A. Yes. On May 3, 2021, VS-CLEO submitted 77 T&D-related interrogatories ("INT") and 22 T&D-related requests for production of documents ("RPOD"). On May 24, 2021, the Company objected to most of the T&D-related INT and RPOD. Subsequently, FPL/Gulf has provided limited responses to many of the T&D-related requests. VS-CLEO received the last set of limited T&D-related responses one week ago, on June 14, 2021.

Q. What is your experience with the discovery process and the type of information utilities typically provide in T&D-related proceedings?

A. In other T&D general rate case ("GRC") and grid modernization proceedings I've participated in (involving requests for significantly less capital than what FPL-Gulf is proposing), there have been detailed utility filings, a robust discovery process with detailed utility responses, and ample opportunity for Commissions, staff, and stakeholders to understand the underlying data/analyses supporting a utility's request for approval of capital expenditures.

Q. Please provide examples of other utilities providing sufficient information to support their requested T&D or grid modernization expenditures.

A. In the 2019 Virginia State Corporation Commission ("SCC") proceeding reviewing Dominion Energy Virginia's petition for approval of its Grid Transformation Plan ("GTP", SCC Docket PUR-2019-00154), I was an expert witness for the SCC Staff ("Staff"). Dominion was proposing $2.9 billion of customer costs, as measured by the present value of revenue requirements. Dominion's initial filing had over 1,200 pages of testimony and exhibits, including a detailed benefit/cost analysis for its proposed GTP expenditures. Through discovery, we were able to compel Dominion to provide additional information, such as non-confidential, circuit-level reliability data and unit costs, and to correct errors in its analyses. Staff was able to make specific recommendations based on this detailed information, and the SCC ultimately adopted most of Staff's recommendations.[1]

[1] In its March 26, 2020 Final Order, the SCC agreed with Staff's recommendations by approving a new customer information platform, development of a Hosting Capacity Analysis, Cybersecurity, and costs for stakeholder engagement and communication. The SCC also agreed with Staff's recommendation by rejecting the proposed self-healing grid project and associated telecommunications, and the Enterprise Asset Management System.

In the Southern California Edison ("SCE") 2021 GRC proceeding (California Public Utilities Commission Docket A.19-08-013), I was an expert witness for Vote Solar and the Solar Energy Industries Association. SCE's GRC request included $913 million of grid modernization and $1.5 billion of load growth capital expenditures from 2019-2023. SCE provided over 1,500 pages of growth- and grid modernization-related testimony and workpapers with extensive detail in its initial filing. SCE was very responsive throughout the discovery process, providing non-confidential circuit-level information, including historical reliability, peak loads, minimum loads, and installed/forecasted generation capacity.

In the 2019 Xcel Energy request for certification for its Advanced Grid Intelligence and Security ("AGIS") initiative (Minnesota Public Utilities Commission Docket No. E002/M-19-666), I supported Fresh Energy [2] as a technical advisor. Xcel was requesting $234 million of capital from 2020-2024 for its AGIS grid modernization initiative, and its initial AGIS filing included over 1,500 pages of testimony and exhibits. In response to our discovery requests, Xcel Energy provided specific answers to our questions including spreadsheets with details supporting its AGIS benefit/cost analysis.

Q. How does this compare to the T&D-related information provided by FPL-Gulf in this proceeding?

A. In support of the Company's proposed $15.69 billion of T&D expenditures from 2019-2023, witness Spoor's testimony and exhibits are 50 pages, including the cover pages

[2] https://fresh-energy.org/

and table of contents. He also sponsored or co-sponsored 36 pages of documents as Minimum Filing Requirements, none of which help explain the justification for the proposed capital expenditures. As I previously described, the Company's responses to T&D-related discovery requests were very limited.

Q. Please provide a brief summary of your recommendations.

A. I understand that the Company must spend capital for day-to-day reliability improvements and growth. However, it is unclear from the record that the amounts proposed by FPL-Gulf are justified, reasonable, and based on actual needs. I recommend that the Commission make approval of the Company's proposed Reliability/Grid Modernization and Growth capital expenditures contingent upon:

- FPL-Gulf developing a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures demonstrating cost effectiveness and reasonableness.
- FPL-Gulf establishing a T&D capital performance management framework to track and report metrics of Reliability/Grid Modernization and Growth capital spending and achievement of expected outcomes.

III. THE COMPANY'S PROPOSED T&D CAPITAL EXPENDITURES ARE SIGNIFICANT

Q. What are the Company's proposed base T&D capital expenditures?

As shown in Figure 1 below, FPL-Gulf is proposing \$2.9-3.5 billion per year for T&D capital expenditures and a total of \$15.69 billion from 2019-2023 to be recovered in base rates. 73% of the expenditures, or \$11.5 billion from 2019-2023, are for the categories of Reliability/Grid Modernization and Growth. The 2019 values in Figure 1 reflect the Company's actual expenditures and the 2020-2023 values are FPL-Gulf's projected expenditures.[3]

Category	2019	2020	2021	2022	2023	2019-2023 ($)	2019-2023 (%)
Reliability/Grid Modernization	$ 0.94	$ 1.15	$ 1.36	$ 1.12	$ 1.06	$ 5.64	36%
Growth	$ 0.87	$ 0.99	$ 1.40	$ 1.26	$ 1.35	$ 5.86	37%
FPSC Storm Hardening/SPP	$ 0.85	$ 0.96	$ 0.14	$ 0.15	$ 0.15	$ 2.24	14%
Grid Servicing/Support	$ 0.31	$ 0.29	$ 0.34	$ 0.31	$ 0.35	$ 1.61	10%
Regulatory Compliance	$ 0.06	$ 0.06	$ 0.07	$ 0.08	$ 0.07	$ 0.35	2%
Total	$ 3.03	$ 3.45	$ 3.31	$ 2.92	$ 2.98	$ 15.69	100%

Figure 1 – FPL's Proposed T&D Capital Expenditures ($ in billions)[4]

IV. FPL-GULF'S PROPOSED CAPITAL FOR RELIABILITY/GRID MODERNIZATION IS UNSUPPORTED

Q. What initiatives are included in the Company's Reliability category of capital expenditures?

A. As witness Spoor explains, the focus of FPL-Gulf's T&D Reliability initiatives is to reduce day-to-day outages and restoration times.[5] These initiatives are in addition to, but separate from, the Company's planned Storm Protection Plan expenditures. For the Company's distribution system, reliability initiatives include targeted improvement of infrastructure/devices experiencing high numbers of outages, and targeted rehabilitation or replacement of underground cable.[6] For the Company's transmission

[3] According to FPL's supplemental response to OPC's First Request for Production of Documents No. 44, file 'Rate Case Backup - Spoor Testimony.xlsm', attached in Exhibit CV-3.

[4] FPSC Docket No. 20210015-EI, Direct testimony of Michael Spoor on behalf of FPL, filed March 12, 2021, at page 37, line 17 (hereinafter "Spoor Direct").

[5] Spoor Direct at page 16, lines 13-14.

[6] Spoor Direct at page 19, lines 1-20.

system, reliability initiatives include assessments of transmission line and substation equipment, predictive replacement of major equipment, root cause analysis to prevent recurrence of outage events, and targeted maintenance.[7]

Q. How is the Company's reliability compared to other utilities?

A. FPL-Gulf's day-to-day reliability is very good compared to other utilities. In 2019, FPL and Gulf had their best-ever performance results for FPSC T&D System Average Interruption Duration Index ("SAIDI")[8]. FPL's 2019 Distribution SAIDI performance ranked 58% better than the national average, and Gulf's 2019 Distribution SAIDI Performance ranked 41% better than the national average.[9]

In 2020, both FPL and Gulf once again had best-ever performance results for FPSC SAIDI and both had their best-ever FPSC Distribution Momentary Average Interruption Frequency Event Index ("MAIFIe"). Additionally, for the 15th consecutive year, FPL's 2020 FPSC T&D SAIDI was the best among the Florida IOUs, becoming the first investor-owned utility in Florida to achieve FPSC T&D SAIDI of less than 50 minutes.[10]

Q. Are the Company's customers satisfied with this level of reliability?

A. One measure of satisfaction is the number of reliability-related customer complaints. Witness Spoor states that FPL has reduced FPSC reliability-related logged complaints per 10,000 customers by 32% since 2016.[11]

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[7] Spoor Direct at page 20, line 1 through page 21 line 11.
[8] SAIDI = the total number of minutes of service interruption the average customer experiences in a year.
[9] Spoor Direct at page 17, lines 20-22.
[10] *Id*. at page 17, lines 5-22.
[11] *Id*. at page 36, lines 15-16

Q. Why is the Company proposing to invest an additional $3.54[12] billion in 2021-2023 to further improve day-to-day (non-storm) reliability?

A. I'm unclear. There is no explanation in witness Spoor's testimony why further day-to-day reliability improvement is imperative, other than his statement that customers "require, and increasingly expect, improved reliability"[13].

VS-CLEO submitted a request for production of documents ("RPOD") to the Company on May 3, 2021 seeking support for this statement. On June 14, 2021, the Company provided some heavily redacted pages showing results from various marketing surveys.[14] The survey results show that some of FPL-Gulf's customers care about reliability during storms and day-to-day reliability. However, the provided documents do not clearly demonstrate that FPL-Gulf's customers "require, and increasingly expect, improved reliability".

Q. Ideally, how would you evaluate the Company's request for day-to-day reliability-related capital expenditures in this proceeding?

A. The vast majority of customer outages for an electric utility are caused by problems on the distribution system.[15] Ideally, I would first examine distribution circuit information including the number of customers served, circuit length, and historical reliability performance. I would then attempt to understand how proposed capital expenditures are targeted to address specific problematic circuits.

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[12] From Figure 1, the Company is projecting $1.36 billion in 2021, $1.12 billion in 2022, and $1.06 billion in 2023 for Reliability/Grid Modernization.
[13] Spoor Direct at page 8, line 7.
[14] FPL-Gulf Confidential response to VS-CLEO RPOD No. 37.
[15] For example, FPL's 2020 Distribution SAIDI was 47.3 minutes per customer and Transmission SAIDI was 1.2 minutes per customer, according to the 2020 FPL Distribution Reliability Report, p. 4.

Q. Does the Company have this circuit-level information?

A. Yes. The Company publishes much of this information in its annual FPSC Distribution Reliability Report[16] in an appendix titled "Feeder Specific Data and Attached Laterals". The report is in PDF format and VS-CLEO, in a May 3, 2021 interrogatory, requested circuit-level information in a spreadsheet to allow for analysis.

Q. Did the Company provide this circuit-level information?

A. No. On May 24, 2021, the Company objected to the interrogatory in its entirety as "irrelevant, immaterial, overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of relevant admissible evidence."[17]

On June 9, 2021, following discussion and agreement between counsel for FPL and VS-CLEO, the Company provided some system-level information.[18] This, however, is not helpful for assessing circuit-level reliability.

Q. How else would you ideally evaluate the Company's request for reliability-related capital expenditures?

A. For initiatives that involve discrete units of activity, I would like to understand historical volumes of activity, planned volumes of activity, and unit costs per activity. For example, one of the Company's reliability initiatives is the replacement of substation transformer relays. I would like to know how many relays FPL-Gulf has historically replaced each year, the planned number of relay replacements in 2021-2023, and the actual and forecasted unit costs per relay replacement.

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[16] Available at http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability.
[17] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 93, attached in Exhibit CV-3.
[18] Company 6/9/21 Response to VS-CLEO Interrogatory No. 93, attached in Exhibit CV-3.

Q. Has the Company provided this type of information to VS-CLEO?

A. Not completely. In addition to similar requests for volumes and unit costs, VS-CLEO requested this information for substation relays in spreadsheet format on May 3, 2021. The Company objected on May 24, 2021, stating, "FPL objects to this request calling for information to be provided in a specified format. FPL will provide any responsive information in the form that it is kept in FPL's normal course of business."[19]

On June 14, 2021, the company provided the estimated number of relay replacements in 2021-2023. In a specific response to the request for unit costs, the Company stated that it is "designated as Highly Sensitive Information, as that term are [*sic*] used in the Confidentiality Agreements in use in this proceeding. The answer to this interrogatory will be made available for inspection at The Radey Law Firm … (in) Tallahassee, Florida."[20] I'm unable to review the information in Tallahassee on such short notice.

Q. How else would you ideally evaluate the Company's request for day-to-day reliability-related capital expenditures?

A. I would ideally examine the Company's projected reliability improvements from the proposed capital expenditures, the reasonableness of the reliability improvement projections, and the cost-effectiveness of the proposed capital spending.

Q. What day-to-day reliability improvements is the Company projecting from the $3.54 billion Reliability/Grid Modernization expenditures in 2021-2023?

A. VS-CLEO submitted multiple interrogatories and RPODs to the Company on May 3, 2021, seeking details on the expected reliability improvements in SAIDI, SAIFI, and

[19] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 87, attached in Exhibit CV-3.
[20] Company 6/14/21 Response to VS-CLEO Interrogatory No. 87, attached in Exhibit CV-3.

MAIFIe[21] in 2021-2023 from FPL-Gulf's proposed T&D reliability and grid modernization initiatives.[22] On June 9, 2021, the Company responded:

> "T&D reliability initiatives, and the associated investments, are necessary to maintain the current reliability standards and performance as well as the continued improvement in overall system reliability. FPL measures reliability performance at the system level. Power Delivery strives for continual reliability improvement and these initiatives, along with others, have the potential to deliver approximately 2 - 4% annual improvement in SAIDI on top of the current reliability performance, with similar type improvements in the other metrics."[23]

Q. What would a 2-4% annual improvement in day-to-day (non-storm) SAIDI mean for the Company's customers?

A. 2020 T&D SAIDI values for FPL and Gulf were 48.54 and 50.26 minutes respectively.[24] Figure 2 below shows the results of a 3% annual improvement in SAIDI from 2020-2023.

SAIDI
(minutes)

	FPL	Gulf
2020	48.540	50.260
2021	47.084	48.752
2022	45.671	47.290
2023	44.301	45.871

[21] System Average Interruption Frequency Index (SAIFI) = the total number of sustained (> 60 seconds for FPL -Gulf) service interruptions the average customer experiences in a year. Momentary interruptions are those lasting less than 60 seconds, and their frequency is measured by the Momentary Average Interruption Frequency Event Index (MAIFIe).
[22] VS-CLEO Interrogatories Nos. 84, 86(g), 90(a) and RPODs 39, 41, attached in Exhibit CV-3.
[23] Company 6/9/21 Response to VS-CLEO Int. No. 84, attached in Exhibit CV-3.
[24] Company 6/9/21 Response to VS-CLEO Int. No. 93q, attached in Exhibit CV-3.

Figure 2 – Impact of an annual 3% improvement in SAIDI

Q. From Figure 2, how much improvement in outage minutes is the Company projecting by 2023?

A. The Company is projecting approximately 4 minutes improvement for both FPL and Gulf by 2023.

Q. What is the improvement in outage minutes if you assume a 4% annual improvement in SAIDI?

A. Approximately 6 minutes improvement for both FPL and Gulf by 2023.

Q. So the Company is proposing to spend $3.54 billion of capital from 2021-2013 to improve annual day-to-day (non-storm) customer outage time by approximately 4-6 minutes?

A. Yes. That's approximately $600-$900 million of capital per minute of reduced day-to-day (non-storm) customer outage time.

Q. Have the Company's customers indicated a willingness to pay for $600-$900 million of capital (plus associated O&M, financing costs and taxes) for a minute of reduced day-to-day (non-storm) outages?

A. Not that I am aware of. On May 3, 2021, VS-CLEO submitted a Request for Production of Documents requesting data, analyses, studies or reports quantifying the Company's customers' willingness to pay for improved reliability.[25] As I previously explained, on June 14, 2021, the Company provided some heavily redacted pages showing results

[25] VS-CLEO First Request for Production of Documents No. 37(b).

from various marketing surveys.[26] One survey asks if customers would be willing to pay "slightly more" on their monthly bill, and another survey asks customers if they support a "modest increase" in rates for "high quality, safe, and reliable electricity services." During his June 16, 2021 deposition, Mr. Spoor was asked: "In developing your testimony, are you aware of any conversations that took place with customers describing the actual expenditures you're proposing and the actual benefits you're proposing?" Witness Spoor acknowledged that he is not aware of any specific discussions with customers about the magnitude of the Company's proposed Reliability/Grid Modernization capital expenditures.[27]

Q. Can you quantify the economic value to the Company's customers of this expected improvement in reliability?

A. Many utilities use Lawrence Berkeley National Lab's Interruption Cost Estimate ("ICE") Calculator[28] to estimate the economic value to customers from improved reliability. The ICE Calculator is an imperfect tool[29], but can provide indicative values that inform commissions and stakeholders in general rate case and grid modernization proceedings.

[26] *See* FPL's Confidential 6/14/21 Response to VS-CLEO RPOD 37. The quoted portions have been cleared with FPL counsel as non-confidential.
[27] Witness Spoor deposition transcript (dated June 16, 2021), page 26, lines 21-25, attached as Exhibit CV-8.
[28] The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. The tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the US. https://www.icecalculator.com/home
[29] The economic benefits from improved reliability are not directly measurable. Also, the ICE Calculator is dated, as some of the surveys are 20+ years old; it is not statistically-representative for all regions of the U.S.; and it is not appropriate for estimating costs of widespread, long-duration (> 24 hour) interruptions. See https://www.icecalculator.com/recent-updates. Additionally, it is difficult to model the impact of momentary interruptions in the ICE Calculator.

Q. What does the ICE Calculator quantify as the economic value to FPL-Gulf's customers of a 2-4% annual improvement in day-to-day reliability from 2020-2023?

A. I ran the ICE Calculator using an annual 3% reduction in non-storm SAIDI and SAIFI from 2020-2023 for FPL and Gulf.[30] According to the ICE Calculator, the value from this day-to-day reliability improvement to FPL's customers is $1.2 billion and the value to Gulf's customers is $0.1 billion. See Exhibit CV-5 for screenshots of these results from the ICE Calculator.

Q. What do you conclude?

A. It appears that the Company's proposed $3.54 billion Reliability/Grid Modernization expenditures in 2021-2023 for day-to-day reliability improvements may significantly exceed the economic benefits to its customers. I recommend that the Commission require the Company to develop a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures to demonstrate cost effectiveness and reasonableness. A benefit/cost analysis is standard practice for assessing grid modernization plans, and it is particularly important for expenditures of the magnitude proposed by the Company. I will further explain this later in my testimony.

Q. Turning to Grid Modernization, what is included in this category of the Company's proposed capital expenditures?

A. For FPL-Gulf's distribution system, this category includes the deployment of smart devices (automated feeder/lateral/transformer switches and fault current indicators)

[30] Other assumptions: 40 year asset life, 2% inflation, 6% discount rate, 2020 customer counts from FPL's response to OPC's First Production of Documents Supplemental No. 35, 2020 SAIFI = 0.87 for FPL, 0.81 for Gulf.

that automatically identify and/or isolate problematic line sections and/or clear temporary faults, avoiding and/or mitigating interruptions and reducing restoration times and costs.[31] For the Company's transmission system, this category includes rebuilding of the Company's 500kV system (replacing transmission structures with galvanized steel poles), the upgrading/digitizing of substation transformer relays, and installing substation fault information capabilities.[32]

Q. How do you typically evaluate a utility's request for Grid Modernization capital expenditures?

A. In a paper I co-authored in 2020[33] ("Grid Mod Playbook", provided as Exhibit CV-6), we explain that regulators should expect to see, among other information, the following when reviewing a utility's proposed grid modernization plan:

- Specific, measurable goals and objectives.
- A benefit/cost analysis ("BCA") to demonstrate cost effectiveness or cost reasonableness.
- Detailed metrics to track progress of the plan's implementation and to hold the utility accountable for achieving planned outcomes.
- A demonstrated need for the proposed expenditures.

Q. Has the Company provided specific, measurable goals and objectives for its proposed reliability and grid modernization expenditures?

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[31] Spoor Direct at page 18, lines 14-18.
[32] *Id*. at page 40 lines 2-4.
[33] Sara Baldwin, Ric O'Connell, Curt Volkmann. *A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist.* IREC and GridLab. May 2020. https://irecusa.org/publications/a-playbook-for-modernizing-the-distribution-grid-volume-1/ and https://gridlab.org/works/grid-modernization-playbook-report/.

A. No. Witness Spoor states, “With FPL and Gulf’s continued commitment and the necessary investments to employ these initiatives, we expect our superior reliability performance will continue to improve.”[34] I previously explained that, in response to multiple VS-CLEO interrogatories and RPODs, the Company stated that its reliability and grid modernization initiatives “have the potential to deliver approximately 2 - 4% annual improvement in SAIDI on top of the current reliability performance, with similar type improvements in the other metrics.”[35] In his deposition, witness Spoor explained a “two pronged” approach of maintaining existing reliability with continuous improvement.[36] I do not consider this to be a specific goal or objective for the Company’s proposed Reliability/Grid Modernization expenditures. A specific goal or objective would be, for example, “achieve a T&D FPL-Gulf SAIDI of 45 minutes by 2023”.

Q. Has the Company provided a BCA to demonstrate cost effectiveness or cost reasonableness?

A. No. VS-CLEO submitted several interrogatories on May 3, 2021 requesting benefit/cost analyses demonstrating that the benefits of the Company’s various reliability and grid modernization initiatives exceed the costs.[37] FPL-Gulf objected to each of the interrogatories on May 24, 2021.[38]

On June 14, 2021, the Company updated its response and directed VS-CLEO to the FPSC website containing the utilities’ Annual Reliability Reports. The Company stated

[34] Spoor Direct at page 18, lines 6-8.
[35] Company 6/9/21 Response to VS-CLEO Int. No. 84, attached in Exhibit CV-3.
[36] Spoor deposition transcript, pages 27, 38, attached in Exhibit CV-8.
[37] VS-CLEO Interrogatories Nos. 86(a), 90(b), 91(a), and 91(b), attached in Exhibit CV-3.
[38] Company 5/24/21 Objections to VS-CLEO’s Interrogatories Nos. 86, 90, and 91, attached in Exhibit CV-3.

that these reports include "costs and benefits of FPL's various reliability and hardening initiatives".[39] During his deposition, witness Spoor admitted that the Annual Reliability Reports do not include a full benefit/cost analysis.[40]

In the same June 14, 2021 response, the Company also directed VS-CLEO to the SPP rebuttal testimony of Michael Jarro in FPSC Docket No. 20200071- EI, stating that it contains "a generally applicable description of how cost benefit analyses relate to reliability programs". In his deposition, witness Spoor acknowledged that Jarro's testimony is not relevant for capital expenditures to improve day-to-day reliability.[41] Witness Spoor also admitted that the Company has, in fact, not developed a Benefit Cost Analysis for its proposed Reliability/Grid Modernization expenditures.[42]

Q. Has the Company provided detailed metrics to track progress of its capital expenditures and to track achievement of planned outcomes?

A. No.

Q. Has the Company demonstrated a need for the proposed investments?

A. No. As explained earlier, the Company's day-to-day reliability performance is already very good compared to other utilities, and the Company's reliability-related customer complaints are down significantly since 2016. Company witness Reed's testimony further supports this, stating, "My benchmarking analysis shows that FPL has consistently and substantially out-performed similarly sized companies across a wide

[39] Company 6/14/21 Response to VS-CLEO INT 86(a), attached in Exhibit CV-3.
[40] Spoor deposition transcript, pages 45-51, attached in Exhibit CV-8.
[41] *Id*.
[42] *Id*.

array of financial and operational metrics including … service quality and system reliability."[43]

Q. What do you recommend?

A. I recommend that the Commission, prior to approval of the Company's proposed Reliability/Grid Modernization expenditures, require FPL-Gulf to develop a comprehensive BCA demonstrating cost effectiveness and reasonableness.

Q. What should be included in a comprehensive benefit/cost analysis or BCA?

A. As we explain in the Grid Mod Playbook, a comprehensive BCA includes:

- An appropriate BCA methodology (e.g., least-cost/best-fit, benefit/cost ratio, etc.) for each category of expenditures.
- Disclosure of all planned Grid Mod expenditures including those beyond the initial period of the request.
- Costs reflecting the full revenue requirements and customer bill impacts over the life of the assets.[44]
- Cost contingencies and a corresponding range of potential BCA results.[45]
- Reasonable and credible benefits from improved reliability.[46]

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[43] FPSC Docket No. 20210015-EI, FPL Direct testimony of John J. Reed, filed March 12, 2021, at page 7, lines 6-10.

[44] In addition to capital and O&M costs, the BCA should include full financing costs and taxes over the life of the assets, as measured by the present value of revenue requirements.

[45] Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all BCA assumptions and calculations, it is important that the utility's inclusion of cost contingencies be explicit and transparent.

[46] Although the determination of reasonable and credible benefits is subjective, the Grid Mod plan should include clear, understandable, and verifiable data/analysis in support of claimed benefits. The ranges of benefits should be consistent with what the utility has demonstrated in pilots, prior deployments, or with what other utilities have realized deploying similar technologies.

- Use of an appropriate discount rate in the BCA calculations.
- Transparency of and support for key BCA assumptions, and a sensitivity analysis of those assumptions.[47]

Q. Are there other resources the Company can use to help evaluate the cost effectiveness of its Reliability/Grid Modernization expenditures?

A. Yes. The Department of Energy ("DOE") published its 4-volume Modern Distribution Grid Report in 2020, which includes a Strategy and Implementation Guidebook.[48] This Guidebook contains a chapter on a Methodology to Evaluate the Cost-Effectiveness of Investments.

The DOE, together with Synapse, also published a report in February 2021, titled *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*.[49] The report reflects a review of 21 recent utility grid modernization plans, and is provided as Exhibit CV-7.

Q. What else do you recommend?

A. To increase transparency into the Company's capital expenditures and to hold the Company accountable for achieving expected outcomes, I recommend that the Commission require the Company to work with stakeholders to establish a T&D capital performance management framework ("Framework") for its largest categories of

[47] A typical Grid Mod plan BCA includes multiple assumptions such as future reliability improvements, equipment failure rates, customer participation in DSM programs, EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions. A sensitivity analysis also identifies the assumptions that have the most impact on the overall costs and benefits of the Grid Mod plan, thus highlighting the key assumptions that the utility should further validate, monitor, and report on throughout the Grid Mod plan implementation.

[48] https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf

[49] https://www.synapse-energy.com/sites/default/files/GMLC-Grid-Mod-BCA-2021-02-02-18-094.pdf

expenditures, including Reliability/Grid Modernization. The Framework should include:

- Metrics to track progress and achievement of expected outcomes for each major capital category.
- Baselines, targets, and actuals for each metric.
- A process for ongoing tracking and reporting of metrics including costs and benefits.

I provide examples of potential metrics in Exhibit CV-4.

Q. How is this different from the Annual Reliability Reports that FPL and Gulf already file with the FPSC?

A. The Annual Reliability Reports are voluminous, providing detailed information on the Company's historical reliability performance, and one-year budgets for certain reliability-related programs. The Framework I'm recommending more closely associates capital expenditures with planned and actual outcomes for both Reliability/Grid Modernization and Growth.

V. FPL-GULF'S PROPOSED CAPITAL FOR GROWTH IS UNSUPPORTED

Q. What is included in the Company's proposed $5.86 billion from 2019-2023 for Growth?

A. This category includes the installation of new service lines for 425,000 new service accounts by 2023, expansion and upgrades of T&D facilities/infrastructure, and other large major construction projects and new streetlight systems.[50]

[50] Spoor Direct at page 38, line 19 through page 39, line 2.

Q. How has the Company explained the need for these expenditures?

A. In only two pages of Witness Spoor's testimony, he attributes the need to FPL's fast growing service area and cites three examples of growth-related major capital projects.[51]

Q. What additional information did VS-CLEO seek to obtain to better understand the need for $5.86 billion of Growth capital?

A. On May 3, 2021, VS-CLEO submitted an RPOD seeking all studies, reports, data, analyses, assumptions, and spreadsheets supporting the request for $5.86 billion of Growth capital. On June 9, 2021, the Company responded by referring VS-CLEO to a spreadsheet titled 'Rate Case Backup – Spoor Testimony.xlsm'.[52] The spreadsheet consists of one tab with seven tables containing high-level summaries of proposed costs. There is no explanation of how the Company derived the costs. In his deposition, witness Spoor stated that he is unaware of any additional information supporting FPL's proposed Growth expenditures.[53]

Q. Ideally, how would you evaluate the Company's proposed growth-related capital expenditures?

A. Ideally, I would first seek to understand the state of the Company's distribution system and distribution planning process, including such information as historical and forecasted peak loads across its various planning areas, its approach to load forecasting, and how it accounts for the impact of demand side management and distributed energy resources.

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[51] Spoor Direct at pages 25-26.
[52] Company 6/9/21 Response to VS-CLEO RPOD 44, attached in Exhibit CV-3.
[53] Spoor deposition transcript at pages 52-55, attached in Exhibit CV-8.

Q. Has the Company provided this information?

A. No. VS-CLEO submitted an interrogatory on May 3, 2021 requesting details on the Company's distribution planning process. On May 24, 2021, the Company objected to much of the interrogatory as "irrelevant, immaterial, and not reasonably calculated to lead to the discovery of relevant admissible evidence in this base rate proceeding".[54]

Subsequently, on June 7, 2021, the Company provided a few high-level responses to the same interrogatory.[55] This is, however, insufficient to provide a detailed understanding of the Company's distribution system, approach to distribution planning, and the justification for $5.86 billion of Growth capital expenditures.

Q. What do you recommend?

A. As I previously explained, to increase transparency and to hold the Company accountable for achieving expected outcomes, I recommend that the Commission require the Company to establish a T&D capital performance management framework. This Framework should include Growth capital expenditures. I provide examples of potential growth-related metrics in Exhibit CV-4.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I recommend that the Commission, before approving the Company's proposed Reliability/Grid Modernization and Growth capital expenditures, require the Company to:

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[54] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 92, attached in Exhibit CV-2.

[55] Company 6/7/21 Response to VS-CLEO Interrogatory No. 92, attached in Exhibit CV-2.

- Develop a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures demonstrating cost effectiveness and reasonableness. Pages 21-22 of my testimony and Exhibit CV-7 describe some important attributes of a comprehensive benefit/cost analysis.
- Work with stakeholders to establish a T&D capital performance management Framework for the Company's Reliability/Grid Modernization and Growth capital expenditures. The Framework should include:
  - Metrics to track progress and achievement of expected outcomes (see VS-CLEO Exhibit CV-4 for potential metrics).
  - Baselines, targets, and actuals for each metric.
  - A process for ongoing tracking and reporting of metrics including costs and benefits.

Q. Does this conclude your testimony?

A. Yes.

VS-CLEO Exhibit CV-2 - Statement of Qualifications for Curt Volkmann

Professional Experience

I am currently President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with environmental and consumer advocates in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization.

I have 36 years of experience in the utilities industry. Prior to founding New Energy Advisors, I worked for the Environmental Law & Policy Center (ELPC) in Chicago as a Senior Clean Energy Specialist. My work at ELPC focused on providing technical advice and expert witness testimony in several renewable energy and energy efficiency regulatory proceedings.

Prior to ELPC, I was employed for eighteen years by Accenture, a global management consulting and technology firm. I held several positions at Accenture, including Executive Director in Accenture's North America Utilities practice, with client leadership responsibilities for several gas, electric, and water utilities. In this role, I oversaw utility cost reduction and operational improvement programs.

Prior to Accenture, I worked for the consulting firm UMS Group, where I led multi-utility benchmarking studies examining global best practices in electric transmission and distribution. Participating utilities in the studies were from the United States, Canada, Australia, New Zealand, Europe, and Africa.

I began my professional career working for nine years at Pacific Gas and Electric in various transmission and distribution roles. This included a role as a Distribution Planning Engineer, where I evaluated the impacts of cogeneration on distribution system protection and the impacts of demand-side management programs on the deferral of distribution substation upgrades.

Education

I have a BS in Electrical Engineering from the University of Illinois at Urbana-Champaign with a concentration in Electrical Power Systems. I also received an MBA from the University of California at Berkeley with a concentration in Finance.

I held a license as a Registered Professional Electrical Engineer in California from 1987 to 1995.

Prior Testimony & Comments by Curt Volkmann

Prior Testimony Filed by Curt Volkmann
(as of May 28, 2021)

State	Date	Proceeding	Case/Docket #
AZ	2/25/16 and 4/7/16	Arizona Corporation Commission investigation into the value and cost of distributed generation	E-00000J-14-0023
	5/19/17 and 9/29/17	The Application of Tucson Electric Power Company for approval of its 2016 renewable energy standard implementation plan	E-01933A-15-0239
	5/19/17 and 9/29/17	The Application of UNS Electric, Inc. for the establishment of just and reasonable rates and charges	E-04204A-15-0142
AR	8/19/16 and 9/9/16	Arkansas Public Service Commission (APSC) in the matter of net metering and the implementation of Act 827 of 2015	16-027-R
	8/26/16 and 9/23/16	APSC investigation of policies related to distributed energy resources	16-028-U
CA	5/2/17	California Public Utilities Commission (CPUC) review of Southern California Edison's application for authority to increase its authorized revenues in 2018	A.16-09-001
	7/26/19	CPUC review of the application of Pacific Gas and Electric Company for authority to increase rates and charges for electric and gas service in 2020.	A.18-12-009
	5/5/20	CPUC review of Southern California Edison's application for authority to increase its authorized revenues in 2021	A.19-08-013
IL	10/18/13	Illinois Commerce Commission (ICC) approval of Ameren IL's Energy Efficiency and Demand Response Plan	13-0498

Prior Testimony Filed by Curt Volkmann (continued)
(as of May 28, 2021)

State	Date	Proceeding	Case/Docket #
IL (cont.)	11/14/13	ICC approval of ComEd's Energy Efficiency and Demand Response Plan	13-0495
	12/4/14	ICC investigation of ComEd's cost of service for low-use residential customers	14-0384
	6/20/18 and 8/10/18	Ameren IL proceeding for approval of its customer generation rebate and customer generation charge pursuant to 220 ILCS 5/16-107.6	18-0537
	7/17/18 and 8/28/18	ComEd proceeding for approval of its customer generation rebate and customer generation charge pursuant to 220 ILCS 5/16-107.6	18-0753
	2/5/21	Investigation into an annual process and formula for the calculation of Ameren IL's distributed generation rebates	20-0389
IA	10/2/18	Iowa Utility Board's approval of Interstate Power & Light's energy efficiency 5-year plan	EEP-2018-0003
	8/1/19	Interstate Power & Light's General Rate Case application and grid modernization plan	RPU-2019-0001
MI	2/24/15	Michigan Public Service Commission in its investigation into the application of Consumers Energy Company to amend its renewable energy plan	U-17752
OH	1/17/19	PUC of Ohio in the matter of the filings by FirstEnergy of a Grid Modernization Business Plan and Distribution Platform Modernization Plan	16-481-EL-UNC and 17-2436-EL-UNC
UT	3/3/20, 7/15/20, 9/15/20	Rocky Mountain Power's application to establish export credits for customer generated electricity	17-035-61 Phase 2

Prior Testimony Filed by Curt Volkmann (continued)
(as of May 28, 2021)

State	Date	Proceeding	Case/Docket #
VA	12/20/19	Virginia State Corporation Commission's review of Dominion's petition for approval of a Grid Transformation Plan	PUR-2019-00154

Prior Comments Filed By or with Contributions From Curt Volkmann
(as of May 28, 2021)

State	Date	Proceeding/Topic	Case/Docket #
CA	8/31/15, 1/26/16, 3/3/16	CPUC's proceeding regarding policies, procedures, and rules for development of Distribution Resources Plans (DRP)	R.14-08-013
MA	5/28/21	Massachusetts Department of Public Utilities' investigation into DER planning and cost assignment	20-75
MI	5/14/18	MPSC's investigation into DTE's and Consumers Energy's five-year distribution investment and maintenance plans	U-20147
	10/5/18	MPSC's Staff Report on a Michigan distribution planning framework	U-20147
MN	9/15/15, 11/18/15, 8/21/17, 9/21/17	Minnesota Public Utilities Commission investigation into grid modernization and distribution planning	E999/CI-15-556
	2/2/18 and 2/28/18	Xcel Energy's 2017 distribution system hosting capacity report	E002/M-17-777
	7/6/18 and 2/22/19	Distribution system planning for Xcel Energy	E002/CI-18-251
	3/17/20 and 4/22/20	Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security certification request	E002/M-19-666
	9/25/20	Stakeholder process informing the metrics, performance evaluation methods, and consumer protection conditions to be applied to Xcel Energy's Advanced Metering Infrastructure and Field Area Network projects	E999/CI-20-627
NY	4/13/18, 5/7/18, 8/27/18	New York Public Service Commission's investigation into the matter of the Value of Distributed Energy Resources (VDER) working group regarding value stack	17-01276

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Florida Power & Light Company for Rate Unification and for Base Rate Increase	Docket No: 20210015-EI Date: May 24, 2021

FLORIDA POWER & LIGHT COMPANY'S SPECIFC OBJECTIONS TO THE CLEO INSTITUTUTE, INC. AND VOTE SOLAR'S FIRST SET OF INTERROGATORIES (NOS. 1-94) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-47)

Florida Power & Light Company ("FPL" or the "Company"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 1.350, Florida Rules of Civil Procedure, Rule 1.050, Florida Rules of Civil Procedure, Rule 28-106.201, Florida Administrative Code, and Rule 28-106.206, Florida Administrative Code, submits the following specific objections to the CLEO Institute, Inc. and Vote Solar's ("CLEO") First Set of Interrogatories (Nos. 1-94) and First Request for Production of Documents (Nos.1-47).

I. Specific Objections

Interrogatory No. 2: FPL objects to the request related to amounts being addressed in the Storm Protection Plans approved in Docket Nos. 20200070 and 20200071 and in the annual Storm Protection Plan Cost Recovery Clause proceedings as that information is beyond the scope of the matters at issue in this proceeding and irrelevant and not reasonably calculated to lead to the discovery of relevant admissible evidence. FPL also objects to this request as being overly broad and unduly burdensome.

Interrogatory No. 3: FPL objects to the request as overly broad, unduly burdensome, irrelevant and not reasonably calculated to lead to the discovery of relevant admissible evidence.

Interrogatory No. 5: FPL objects to the request as irrelevant, not reasonably calculated to lead to the discovery of relevant admissible evidence, and the requested information is not tracked evidence. FPL's last base rate case occurred in 2016, and issues related to information predating 2016 would have been addressed at that time.

Interrogatory No.83: FPL objects to Interrogatory No. 83 as irrelevant, immaterial, and not reasonably calculated to lead to the discovery of relevant admissible evidence in this base rate proceeding. The scope, timing, costs, and expected reliability improvements for the pilot programs to harden laterals are addressed in the Storm Protection Plans approved in Docket Nos. 20200070 and 20200071 and in the annual Storm Protection Plan Cost Recovery Clause proceedings. No costs associated with the pilot programs to harden laterals are included in FPL's requested base rate increase.

Interrogatory No. 85: FPL objects to this request calling for information to be provided in a specified format. FPL will provide any responsive information in the form that it is kept in FPL's normal course of business.

Interrogatory 86: FPL objects to this request, in part, to the extent it requests information or analyses that are outside of what FPL maintains in its ordinary course of business. FPL is not required to create information for other parties or intervenors.

Interrogatory No. 87: FPL objects to this request calling for information to be provided in a specified format. FPL will provide any responsive information in the form that it is kept in FPL's normal course of business.

Interrogatory No. 88: FPL objects to this request calling for information to be provided in a specified format. FPL will provide any responsive information in the form that it is kept in FPL's normal course of business.

Interrogatory Nos. 90: FPL objects to this request, in part, to the extent it requests information or analyses that are outside of what FPL maintains in its ordinary course of business. FPL is not required to create information for other parties or intervenors.

Interrogatory Nos. 91: FPL objects to this request, in part, to the extent it requests information or analyses that are outside of what FPL maintains in its ordinary course of business. FPL is not required to create information for other parties or intervenors.

Interrogatory Nos. 92: FPL objects to Interrogatory No. 92, subparts a, b, c, d, e, i, k, l, m, o, p, q, s, and t , as irrelevant, immaterial, and not reasonably calculated to lead to the discovery of relevant admissible evidence in this base rate proceeding.

Interrogatory Nos. 93: FPL objects to Interrogatory No. 93 in its entirety as irrelevant, immaterial, overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of relevant admissible evidence. FPL also objects to subparts h, i, j and k, because the requested information is not tracked or maintained in FPL's ordinary course of business. FPL is not required to create information for other parties or intervenors.

Request for Production No. 2: FPL objects to the request for all documents related to FPL's "30-by-30" plans as irrelevant, immaterial, overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of relevant admissible evidence; notwithstanding and without waiving such objections, FPL will provide an appropriate response.

Request for Production No. 4: FPL objects to the request for FPL affiliate company information as irrelevant and beyond the scope of the matters at issue in this proceeding. FPL also objects to the request for "all documents" related to FPL's costs to build solar generation as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of relevant admissible evidence.

QUESTION:
Please refer to Witness Spoor's testimony, p. 38-39.

a. Please provide all studies, reports, data, analyses, assumptions, and spreadsheets supporting the request for $1.32 billion of capital from 2019-2023 to add 425,000 new service accounts.

b. Please provide all studies, reports, data, analyses, assumptions, and spreadsheets supporting the request for $0.76 billion of capital from 2019-2023 for expansion and upgrades of both T&D facilities/infrastructure.

c. Please provide all studies, reports, data, analyses, assumptions, and spreadsheets supporting the request for $3.76 billion of capital from 2019-2023 for new large major construction projects and new streetlight systems

RESPONSE:
Please see FPL's specific objections filed on May 24th, 2021. Notwithstanding and without waiving these objections, FPL responds as follows:

a.) For capital please refer to file "*Rate Case Backup – Spoor Testimony*" in Witness Spoor's folder included in FPL's supplemental response to OPC's First Request for Production of Documents No. 36. For new service accounts please refer to FPL's response to OPC's Fourth Request for Production of Documents No. 77.

b.) Please refer to subpart (a) of this response.

c.) Please refer to subpart (a) of this response.

FPL 007168
20210015-EI
PD Capital

Major Driver Table
($'s in Billions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023	%
FPSC Storm Hardening/SPP	$ 0.85	$ 0.96	$ 0.14	$ 0.15	$ 0.15	$ 2.24	$ 2.10	$ 2.24	14%
Growth	$ 0.87	$ 0.99	$ 1.40	$ 1.26	$ 1.35	$ 5.86	$ 4.51	$ 5.86	37%
Reliability/Grid Modernization	$ 0.94	$ 1.15	$ 1.36	$ 1.12	$ 1.06	$ 5.64	$ 4.58	$ 5.64	36%
Grid Servicing/Support	$ 0.31	$ 0.29	$ 0.34	$ 0.31	$ 0.35	$ 1.61	$ 1.26	$ 1.61	10%
Regulatory Compliance	$ 0.06	$ 0.06	$ 0.07	$ 0.08	$ 0.07	$ 0.35	$ 0.27	$ 0.35	2%
Total $BN	**$ 3.03**	**$ 3.45**	**$ 3.31**	**$ 2.92**	**$ 2.98**	**$ 15.69**	**$ 12.72**	**$ 15.69**	**100%**

FPSC Storm Hardening/SPP
($'s in Billions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023
Hardening (Feeders)	$ 0.58	$ 0.67	$ 0.10	$ 0.10	$ 0.08	$ 1.53	$ 1.44	$ 1.53
Hardening (Laterals)	$ 0.06	$ 0.13	$ 0.01	$ 0.01	$ 0.01	$ 0.22	$ 0.21	$ 0.22
Distribution Pole Program	$ 0.06	$ 0.05	$ 0.02	$ 0.02	$ 0.02	$ 0.17	$ 0.15	$ 0.17
T&S Hardening (Storm Secure)	$ 0.09	$ 0.08	$ 0.01	$ 0.00	$ 0.00	$ 0.19	$ 0.19	$ 0.19
Storm Surge Mitigation	$ -	$ 0.00	$ 0.00	$ 0.00	$ -	$ 0.00	$ 0.00	$ 0.00
FPSC Level 1 and 2 Transmission	$ 0.06	$ 0.03	$ 0.01	$ 0.01	$ 0.02	$ 0.13	$ 0.11	$ 0.13
Total $BN	**$ 0.85**	**$ 0.96**	**$ 0.14**	**$ 0.15**	**$ 0.15**	**$ 2.24**	**$ 2.10**	**$ 2.24**

Growth
($'s in Billions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023
New Service Accounts (NSA)	$ 0.24	$ 0.24	$ 0.27	$ 0.28	$ 0.28	$ 1.32	$ 1.04	$ 1.32
T&D System Upgrades	$ 0.06	$ 0.10	$ 0.15	$ 0.20	$ 0.26	$ 0.77	$ 0.50	$ 0.77
Large Major Construction and New Streetlights	$ 0.56	$ 0.65	$ 0.98	$ 0.79	$ 0.80	$ 3.77	$ 2.97	$ 3.77
Total $BN	**$ 0.87**	**$ 0.99**	**$ 1.40**	**$ 1.26**	**$ 1.35**	**$ 5.86**	**$ 4.51**	**$ 5.86**

Reliability/Grid Modernization
($'s in Billions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023
Smart Grid (AFS, ALS, FCI, Smart Grid	$ 0.18	$ 0.21	$ 0.21	$ 0.19	$ 0.19	$ 0.99	$ 0.80	$ 0.99
UG Insp/Repair Programs	$ 0.00	$ 0.04	$ 0.01	$ 0.01	$ 0.01	$ 0.09	$ 0.07	$ 0.09
Other (HH / PMT Insp/SubCable/Cable Rehab etc.)	$ 0.15	$ 0.16	$ 0.23	$ 0.18	$ 0.17	$ 0.89	$ 0.72	$ 0.89
Total Distribution $BN	**$ 0.34**	**$ 0.42**	**$ 0.44**	**$ 0.39**	**$ 0.38**	**$ 1.97**	**$ 1.59**	**$ 1.97**

Targeted assmts/ maint / prevention	$ 0.13	$ 0.15	$ 0.19	$ 0.23	$ 0.24	$ 0.93	$ 0.70	$ 0.93
Major Projects Reliability/Other transmission	$ 0.39	$ 0.30	$ 0.58	$ 0.44	$ 0.44	$ 2.14	$ 1.70	$ 2.14
Total Transmission $BN	**$ 0.52**	**$ 0.45**	**$ 0.76**	**$ 0.67**	**$ 0.68**	**$ 3.08**	**$ 2.40**	**$ 3.08**
NFRC	$ 0.09	$ 0.28	$ 0.15	$ 0.07		$ 0.59	$ 0.59	$ 0.59
Total $BN	**$ 0.94**	**$ 1.15**	**$ 1.36**	**$ 1.12**	**$ 1.06**	**$ 5.64**	**$ 4.58**	**$ 5.64**

Grid Servicing/Support
($'s in Billions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023
Restoring Service	$ 0.13	$ 0.14	$ 0.13	$ 0.13	$ 0.13	$ 0.67	$ 0.54	$ 0.67
Fleet	$ 0.06	$ 0.06	$ 0.04	$ 0.04	$ 0.05	$ 0.25	$ 0.20	$ 0.25
Misc (Cust reqs, comp equip, software)	$ 0.12	$ 0.09	$ 0.17	$ 0.14	$ 0.17	$ 0.69	$ 0.52	$ 0.69
Total $BN	**$ 0.31**	**$ 0.29**	**$ 0.34**	**$ 0.31**	**$ 0.35**	**$ 1.61**	**$ 1.26**	**$ 1.61**

Regulatory Compliance
($'s in Millions)

	2019 Actuals	2020 Projected	2021 Projected	2022 Projected	2023 Projected	Total	2019-2022	2019-2023
Relocations	$ 35.0	$ 28.8	$ 36.0	$ 36.7	$ 36.5	$ 173.0	$ 136.5	$ 173.0
Other (Reg & MP Compliance)	$ 29.5	$ 27.8	$ 37.4	$ 41.3	$ 36.4	$ 172.4	$ 136.0	$ 172.4
Total $BN	**$ 64.5**	**$ 56.6**	**$ 73.5**	**$ 78.0**	**$ 72.9**	**$ 345.5**	**$ 272.5**	**$ 345.5**

PD O&M
($'s in Millions)

	2022 Projected	2023 Projected
T&D O&M Base	$ 206.6	$ 212.5
T&D SPP O&M	$ 83	$ 83
Total $BN	**$ 289.7**	**$ 295.4**

QUESTION:
Please refer to Witness Spoor’s testimony, p. 16, lines 13-14. Please provide the expected improvements in SAIDI, SAIFI, and MAIFIe in 2021-2023 from FPL’s T&D reliability initiatives.

RESPONSE:
T&D reliability initiatives, and the associated investments, are necessary to maintain the current reliability standards and performance as well as the continued improvement in overall system reliability. FPL measures reliability performance at the system level. Power Delivery strives for continual reliability improvement and these initiatives, along with others, have the potential to deliver approximately 2 - 4% annual improvement in SAIDI on top of the current reliability performance, with similar type improvements in the other metrics. FPL’s investments have resulted in best ever SAIDI in 2019 and that performance was improved upon again in 2020 as shown in FPL witness Spoor’s Exhibits MS-3, MS-4, MS-5, and MS-6. Additionally, customer reliability-related complaints have improved by 32% from 2020 versus 2016, a testament to the impact of investing in the overall reliability of the grid. Overall system reliability performance, measured over multiple years, remains the best tool to determine improvements and customer benefits for the totality of all programs, processes, and initiatives implemented, and this has been recognized by the Commission.

QUESTION:
Please refer to Witness Spoor's testimony, p. 18, lines 12-22.

a. Please provide, in spreadsheet form, FPL's benefit/cost analysis demonstrating that the benefits of its Grid Modernization/Smart Grid program exceed the costs for FPL's customers.

b. Please explain FPL's strategy or approach to deploying smart devices including the typical number of AFS, ALS, ATS and FCI per distribution circuit.

c. Please explain how FPL prioritizes circuits for deployment of smart devices.

d. Please explain how minority and low-income communities are benefiting from FPL's deployment of smart devices.

e. Please provide the total number of FPL and Gulf distribution circuits, the current number of circuits with AFS/ALS/ATS/FCI, and the planned number of circuits with AFS/ALS/ATS/FCI by 2023.

f. Please provide a spreadsheet containing the number of actual or planned installations of AFS, ALS, ATS and FCI devices each year 2019-2023.

g. In the same spreadsheet as f), please provide the expected improvements in SAIDI, SAIFI, and MAIFIe from the deployment of smart devices each year 2019-2023.

h. Please provide typical unit costs for AFS, ALS, ATS and FCI installations

RESPONSE:
Subject to and without waiving FPL's specific objections filed on May 24th, 2021 and general objections filed contemporaneously with this response, FPL responds as follows

a. The Florida Public Service Commission ("FPSC" or "Commission") has recognized the importance of reliability as per their requirement to file the Annual Reliability Filing per 25.60455 F.A.C. available at - http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability which includes costs and benefits of FPL's various reliability and hardening initiatives.

   See also FPL's Storm Protection Plan Rebuttal Testimony filed in Docket No. 20200071-EI at the link provided below for a generally applicable description of how cost benefit analyses relate to reliability programs.
   http://www.psc.state.fl.us/library/filings/2020/03369-2020/03369-2020.pdf

QUESTION:
Please refer to Witness Spoor's testimony, p. 20, line 13.

a. Please explain FPL's strategy or approach for determining when to upgrade a substation transformer relay.

b. Please provide the number of actual or planned substation transformer relay upgrades each year 2019-2023 in spreadsheet form.

c. Please provide typical unit costs for substation transformer relay upgrades.

RESPONSE:
Subject to and without waiving FPL's specific objections served May 24th, 2021 and general objections served contemporaneously with this response, FPL responds as follows:

a. FPL's strategy is based on several factors such as equipment age, standardization, and material obsolescence, all of which are a contributing factor in determining when a substation transformer relay scheme is scheduled for upgrade or replacement. FPL also factors in customer service impact and overall reliability and system performance into the scheduled upgrades to eliminate possible failures of aging equipment and avoidance of unscheduled customer interruptions. FPL incorporates equipment standardization across the system as part of the overall strategy of upgrading substation transformer relay schemes to create efficiency and improve system performance. Finally, new technology usually provides expanded functionality and options that provide all our customers with improved reliability when incorporated within other projects and system improvements.

b.

	Actual 2019	Actual 2020	Actual/Estimated 2021	Estimated 2022	Estimated 2023
Upgrade a substation transformer relay[1]	12	22	48	44	44

[1] Estimates could vary based on a number of factors, including, but not limited to: permitting, easement issues, change in scope; resource constraints, and/or extreme weather.

c. FPL's response to Vote Solar-CLEO's First Set of Interrogatory No. 87(c) is designated as Highly Sensitive Information, as that term are used in the Confidentiality Agreements in use in this proceeding. The answer to this interrogatory will be made available for inspection at The Radey Law Firm located at 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301, provided the reviewing party has executed the Confidentiality Agreement and remains in compliance with the requirements of the Confidentiality Agreement associated with the review of Highly Sensitive Information.

QUESTION:
Please provide the following information regarding FPL's distribution planning process:

a. Names of FPL and Gulf distribution planning areas;
b. Distribution substations and circuits in each planning area;
c. Number of residential, commercial, and industrial customers in each planning area;
d. Peak load in each planning area for each of the years 2016, 2017, 2018, 2019 and 2020;
e. Forecasted peak load in each planning area for each of the years 2021, 2022, and 2023;
f. Distribution planning criteria and design guidelines used by FPL to determine the need for new or upgraded circuits or substations;
g. Steps in FPL's distribution planning process, including timing and duration of each step;
h. Organization(s) and fulltime-equivalent FPL employees and contractors involved in the distribution planning process;
i. Software tools utilized by FPL for forecasting, system modeling/mapping, power flow analysis, fault current analysis, or related distribution planning analyses;
j. FPL's process for prioritizing distribution capacity and reliability projects;
k. FPL's tools, methodology, and process for calculating and publishing distribution circuit hosting capacity;
l. FPL's tools, methodology, and process for determining circuit and substation peak loads;
m. FPL's tools, methodology, and process for determining circuit daytime minimum loads;
n. FPL's tools, methodology, and process for load forecasting;
o. FPL's private solar forecasting tools and methodology;
p. FPL's forecasting tools and methodologies for other forms of distributed energy resources (e.g., non-solar distributed generation, energy efficiency, demand response, electric vehicles, and energy storage);
q. A description of how FPL's distribution planning process is integrated with FPL's private solar interconnection process;
r. A description of how FPL's distribution planning process is integrated with transmission planning;
s. A description of how FPL's distribution planning process is integrated with FPL's demand-side management programs and program planning; and
t. Inverter voltage and reactive power modes and settings FPL requires for private solar customers (e.g., constant unity power factor, volt/VAR with reactive power priority, etc.) and the rationale for this requirement.

RESPONSE:
a. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

b. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

c. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

d. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

e. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

f. FPL relies on established distribution planning guidelines and criteria for operating a balanced 3 phase distribution system at or below manufacturer prescribed equipment ratings. This is determined by customer load growth and the need for additional circuits and/or substations based on current capacity in the area. The existing annual process ensures FPL distribution planning evaluates all distribution feeders and substation transformers to operate within prescribed operating criteria. The process has been proven over time and it is reflected in FPL's repeated reliability performance.

g. FPL distribution planning process and timing are highly detailed and involved processes performed annually. These require a significant number of Company personnel and systems, collaborating throughout the year, to build the annual distribution planning model. At a high level, these steps require combining the GIS model, impedance model and equipment database, as well as historical load data and customer data from across the system. The information is modeled into Synergi, an off-the-shelf application, that performs planning simulations across the distribution system and identifies areas at risk. This, in turn, helps the team manage the distribution planning process and areas that require further review, study, and analysis. The detailed steps for the entire duration from start to finish last approximately 9 – 12 months, considering the individual steps required throughout the year to build an accurate model, run the subsequent analysis, review results, develop alternate proposals and evaluate projects for approval and eventual budgeting.

h. FPL has a total of 16 total planning staff members and contractors whose primary responsibility is distribution planning. FPL distribution planning group is supported not only by the individual planning staff and contractors, but also by a large number of individuals throughout multiple business units. These include distribution service planners, GIS team, technical services engineers, control center leads, diagnostic center engineers, customer service advisors and account managers throughout FPL's service area. The combined efforts and collaboration from these teams help build the annual Synergi model for analysis.

i. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

j. FPL conducts an annual review of all known active customer load growth activities throughout its service area and determines the need for additional circuits and substations based on current capacity and active load growth. Additional reliability-driven projects are determined based on the highest customer count substations, circuits and line sections, as well as our worst performing circuits that experience the highest number of interruption minutes. FPL's reliability projects are designed to decrease the number of customers affected by any one fault on the system. Total customer counts are used to drive prioritization, as well as projects designed to mitigate specific circuits that experience the most frequent outages.

k. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

l. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

m. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

n. FPL's process for forecasting total system peak demands are described in the direct testimony of FPL Witness Park, pages 40-46. The models used to forecast system peak demands are included the subfolder *Load Forecasting\Peaks* provided in FPL's Supplemental Response to OPC's First Request for Production of Documents No. 35.

o. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

p. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

q. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

r. FPL distribution planning and transmission planning groups report to the same management organization. Both groups work closely and collaborate to evaluate regional load growth, new customer load forecast and general service requests to help establish and determine the need for new substations and/or transmission lines and overall system reliability and performance to meet the needs of our customers.

s. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

t. Please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories.

QUESTION:
Please provide one spreadsheet with the following information for each of FPL's and Gulf's distribution circuits:

a. Substation name and/or ID number;
b. Circuit name and/or ID number;
c. Circuit primary voltage (kV);
d. Total overhead primary circuit miles;
e. Total underground primary circuit miles;
f. Number of residential, commercial, and industrial customers served;
g. Circuit capacity (MW or MVA);
h. Peak load (MW) for each of the years 2016, 2017, 2018, 2019 and 2020;
i. Forecasted 2021 peak load (MW);
j. Forecasted annual peak load growth 2021-2023
k. Daytime minimum load (MW) for each of the years 2016, 2017, 2018, 2019 and 2020;
l. Supervisory Control and Data Acquisition (SCADA)? (Yes or No);
m. Number of automated feeder switches (AFS);
n. Number of automated lateral switches (ALS);
o. Number of automated transfer switches (ATS);
p. Number of fault current indicators (FCI);
q. 2020 SAIDI;
r. 2020 SAIFI;
s. 2020 MAIFIe;
t. Number of existing private solar systems;
u. Capacity of existing private solar systems (MWAC);
v. Forecasted 2023 capacity of private solar systems (MWAC);
w. Number of private solar customers with energy storage;
x. Capacity of private solar energy storage (MW and MWh);
y. Capacity of other energy storage (MW and MWh);
z. Number of existing Level 2 EV chargepoints;
aa. Forecasted number of Level 2 EV chargepoints in 2023;
bb. Number of existing DC fast charging chargepoints;
cc. Forecasted number of DC fast charging chargepoints in 2023;
dd. Forecasted energy (kWh) and demand (kW) for each of the years 2021, 2022, and 2023 from EV charging; and
ee. Capacity of available load-modifying resources such as demand response or load control (kW).

RESPONSE:

For subparts a, b, g, h, i, j, k, l, m, n, o, and p please see FPL's specific objections filed on May 24, 2021 and general objections filed contemporaneously with FPL's responses to Vote Solar-CLEOs First Set of Interrogatories. Additionally, per discussion and agreement between counsel for FPL and Vote Solar-CLEO, FPL is only providing system level data in response to subparts c, d, e, f, q, r, s, t, u, v, w, x, y, z, aa, bb, cc, dd, and ee to the extent it is available.

c. Circuit primary voltage (kV);
   FPL's distribution primary delivery voltages (kV) are: 13 and 23
   Gulf's distribution primary delivery voltages (kV) are: 12 and 25

d. Total overhead primary circuit miles;
   Please refer to FPL (Pg. 16) and Gulf's (Pg. 13) Annual Reliability Filings to the Florida Public Service Commission available at:
   http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability

e. Total underground primary circuit miles;
   Please refer to FPL's response to CLEO/Vote Solar's First Set of Interrogatories, No. 93d.

f. Number of residential, commercial, and industrial customers served:
   Please see OPC's First Production of Documents Supplemental No. 35, in the subfolder *Load Forecasting\Customers\energy_build* file named "energy_build_v11".

q. 2020 SAIDI.
   FPL T&D 2020 SAIDI: 48.54
   Gulf T&D 2020 SAIDI: 50.26

r. 2020 SAIFI.
   FPL T&D 2020 SAIFI: 0.87
   Gulf T&D 2020 SAIFI: 0.81

s. 2020 MAIFIe.
   FPL Distribution 2020 MAIFIe: 2.60
   Gulf Distribution 2020 MAIFIe: 1.44

t. Number of existing private solar systems; 2020 Data:
   FPL: 23,799
   Gulf: 5,672

u. Capacity of existing private solar systems (MWAC); 2020 Data:
   FPL: 222
   Gulf: 46

v. Forecasted 2023 capacity of private solar systems (MWAC).
FPL: 451
Gulf: 69

w. Number of private solar customers with energy storage:
Energy storage data is self-reported by customers as part of the net-metering interconnection process; no compulsory mechanism exists for FPL or Gulf to track the installation of customers' behind the meter energy storage systems. As of March 31, 2021, FPL is aware of 1,006 net-metering accounts that have installed battery storage systems.

x. - dd. With respect to subparts x through dd, FPL and Gulf do not have a forecast for charging stations. However, as part of FPL and Gulf's most recent Ten-Year Site Plan, FPL and Gulf provided the information in the table below. This is not an internal forecast but instead represents WoodMac's US Forecast, scaled to FPL and Gulf service area based on Alternative Fuel Station Locator's year-end actuals.

Utility	Year	Number of PEVs(1)	Number of Public PEV Charging Stations(2)	Number of Public DCFC PEV Charging Stations.(2)	Cumulative Impact of PEVs(3)		
					Summer Demand (MW)	Winter Demand (MW)	Annual Energy (GWh)
Gulf	2021	1,981	165	31	1	0	1
	2023	3,049	302	62	3	1	5
FPL	2021	49,282	4,007	761	13	5	43
	2023	75,862	7,320	1,502	70	25	217

Notes:
1) Includes cars and trucks
2) Charging Stations represent estimated number of ports in FPL service area. Quick-charge PEV station ports included in total Number of Public PEV Charging Stations.
3) MW and GWh are incremental from the end of 2020

ee. The current and projected amounts of load control/demand response are presented in the FPL/Gulf 2021 Ten-Year Site Plan. The Summer values are presented on Schedule 3.1, pages 66 and 67. The Winter values are presented in Schedule 3.2, pages 68 and 69. Please refer to this document for the requested information.

Potential Metrics for FPL-Gulf T&D Capital Performance Management

Driver	Program/Initiative	Metric	Units	Baseline	2022 Planned Units	2022 Budget	2022 Actual Units	2022 Actual Cost
Reliability / Grid Modernization	All	T&D SAIDI - FPL	minutes	48.54	45.67	N/A	TBD	N/A
		T&D SAIDI - Gulf	minutes	50.26	47.29	N/A	TBD	N/A
		T&D SAIFI - FPL	interruptions	0.87	0.82	N/A	TBD	N/A
		T&D SAIFI - Gulf	interruptions	0.81	0.76	N/A	TBD	N/A
	500 kV Rebuild	# of Structures Replaced	structures	1,506	820	TBD	TBD	TBD
	Substation Transformer Relay Upgrades	# of Relays Upgraded	relays	48	44	TBD	TBD	TBD
	Transmission Substation Assessments	# of Substations Assessed	substations	TBD	TBD	TBD	TBD	TBD
	Transmission Line Assessments	Miles of Line Assessed	miles	TBD	TBD	TBD	TBD	TBD
	Distribution Automation / Smart Grid	# of AFS installed	AFS devices	930	800	TBD	TBD	TBD
		# of ALS installed	ALS devices	3,084	TBD	TBD	TBD	TBD
		# of ATS installed	ATS devices	15,000	12,400	TBD	TBD	TBD
		# of FCI installed	FCI devices	4,040	TBD	TBD	TBD	TBD
	Underground cable rehabilitations	Miles rehabilitated	miles	TBD	TBD	TBD	TBD	TBD
	Underground cable replacements	Miles replaced	miles	TBD	TBD	TBD	TBD	TBD
	Submarine cable replacements	Miles replaced	miles	TBD	TBD	TBD	TBD	TBD
	Handhole inspection/remediation	# of handholes inspected	handholes	TBD	TBD	TBD	TBD	TBD
	Padmount transformer inspection/remediation	# of transformers inspected	transformers	TBD	TBD	TBD	TBD	TBD
Growth	New service line installations	# of service lines installed	service lines	TBD	TBD	TBD	TBD	TBD
	New streetlight installations	# of streetlights installed	streetlights	TBD	TBD	TBD	TBD	TBD
	New transmission capacity	MVA added	MVA	TBD	TBD	TBD	TBD	TBD
	New distribution capacity	MVA added	MVA	TBD	TBD	TBD	TBD	TBD

AFS = Automated Feeder Switch, ALS = Automated Lateral Switch, ATS = Automated Transformer Switch, FCI = Fault Current Indicator

ICE Calculator Screenshots – 6/10/21

FPL

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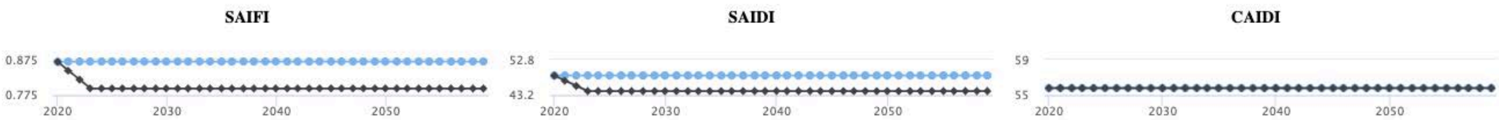
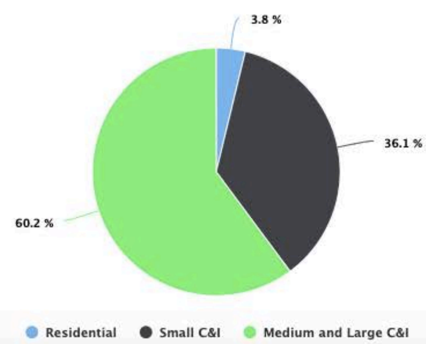
Initial Year	Lifetime (Years)	Inflation Rate	Discount Rate	#Residential	#Non-Residential	
2020	40	2.0 %	6.0 %	4545795	578405	Florida



Distribution of Benefits

Sector	# of Customers	Total Benefit (2020$)	Benefit Per Customer (2020$)
Residential	4,545,795	$46,004,416.05	$10.12
Small C&I	461,231	$439,145,187.54	$952.12
Medium and Large C&I	117,174	$732,500,478.98	$6,251.39
All	5,124,200	$1,217,650,082.57	$237.63



Gulf

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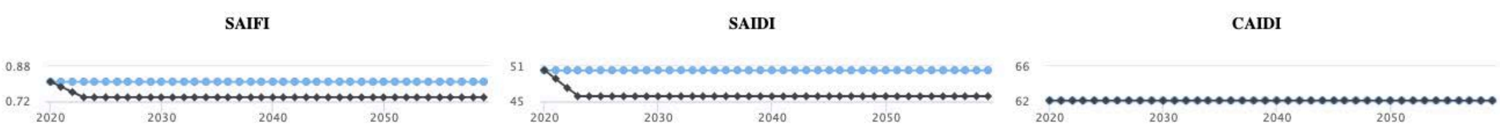
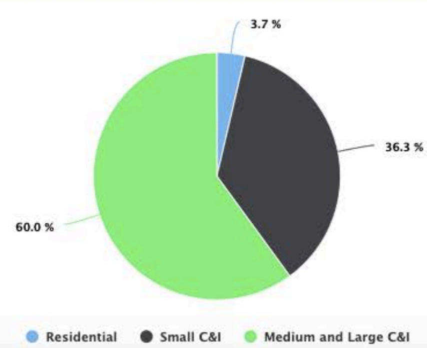
Initial Year	Lifetime (Years)	Inflation Rate	Discount Rate	#Residential	#Non-Residential	
2020	40	2.0 %	6.0 %	411516	52898	Florida



Distribution of Benefits

Sector	# of Customers	Total Benefit (2020$)	Benefit Per Customer (2020$)
Residential	411,516	$3,909,028.89	$9.50
Small C&I	42,182	$38,656,021.47	$916.41
Medium and Large C&I	10,716	$63,949,907.73	$5,967.70
All	464,414	$106,514,958.09	$229.35



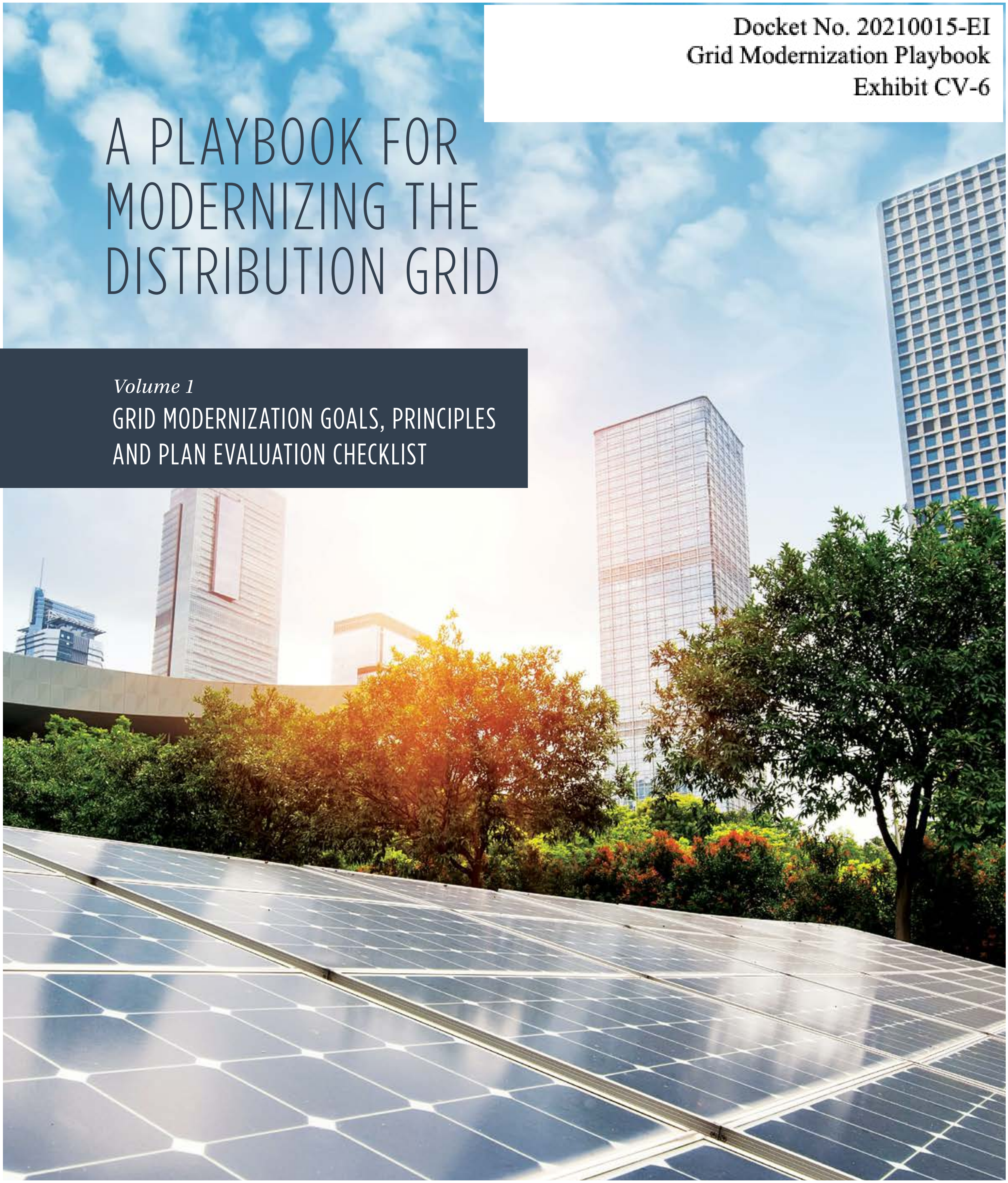
Screenshot

Docket No. 20210015-EI
Grid Modernization Playbook
Exhibit CV-6

A PLAYBOOK FOR MODERNIZING THE DISTRIBUTION GRID

Volume 1

GRID MODERNIZATION GOALS, PRINCIPLES AND PLAN EVALUATION CHECKLIST



IREC GridLAB

ABOUT THE PLAYBOOK

Developed by the Interstate Renewable Energy Council (IREC) and GridLab, A Playbook for Modernizing the Distribution Grid (hereinafter, the GridMod Playbook) is an evaluation toolkit to help regulatory stakeholders navigate, analyze and make more informed decisions about grid modernization proposals, distribution plans and grid investments. The GridMod Playbook aims to ensure more efficient and impactful grid modernization efforts in support of state public policy goals, such as clean energy adoption, across the United States and U.S. territories.

The first volume, *Grid Modernization Goals, Principles and Plan Evaluation Checklist*, consists of goals and principles for grid modernization, and an evaluation checklist – combined, they provide an initial framework to help utility regulators and regulatory stakeholders assess the merits of proposed grid modernization plans, investments and initiatives. The GridMod Playbook concept was developed at Rocky Mountain Institute (RMI)'s 2019 eLab Accelerator. This volume was developed by IREC and GridLab with peer review and input from the following individuals. No part of this document should be attributed to these individuals or their affiliated organizations.

- **Joseph Pereira,** *Colorado Office of Consumer Counsel*
- **Ed Smeloff,** *Vote Solar*
- **Chaz Teplin,** *Rocky Mountain Institute*
- **Steven Rymsha,** *Sunrun*
- **Karen Olesky,** *Public Utilities Commission of Nevada*
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SUGGESTION CITATION

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CONTENTS

About IREC

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy and our planet. IREC develops, informs and advances the regulatory reforms, technical standards, and workforce solutions needed to enable the streamlined, efficient and cost-effective installation of clean, distributed energy resources. www.irecusa.org

About GridLab

GridLab is an innovative non-profit that provides technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future. www.gridlab.org

GOALS OF GRID MODERNIZATION

Over 150 states, local governments and prominent businesses have adopted ambitious renewable and clean energy goals to rapidly reduce carbon emissions in an effort to address climate change and improve the resilience of the electric grid. Concurrently, states and utilities are undertaking "grid modernization" efforts that could enable strategic investments in new technologies for the distribution grid and allow for increased grid integration of distributed energy resources (DERs) and accompanying technologies — e.g., solar, energy storage, advanced meters, smart inverters, smart devices, demand response and electric vehicle (EV) charging infrastructure. These grid modernization efforts have the potential to leverage the deployment of DER technologies to meet policy and customer goals, while also creating more transparency and minimizing the risks associated with future grid investments.

Utilities across the country are proposing investments that add up to billions of ratepayer dollars over the next several years. Although considerable investments in the distribution grid will be needed in the coming decades to address aging infrastructure and changing demands on the electricity grid, not all grid modernization investments may be warranted or beneficial, either economically or for carbon emission reductions.

Although state policymakers, regulators and utilities may articulate discrete goals for their respective grid modernization efforts, we believe the overarching goals of grid modernization plans and ensuing investments should be to enable the swift evolution of the grid to integrate modern technologies that meet public policy and clean energy objectives, such as reducing carbon emissions and achieving 100% clean energy goals. In particular, grid modernization plans and investments should cost-effectively enable, not hinder, the electrification and decarbonization of the vehicle and building sectors, support increased energy efficiency, facilitate the deployment of DERs and improve grid reliability and resilience. The latter is especially critical given the increased frequency and intensity of natural disasters, which will only be further exacerbated by climate change. In addition, grid modernization should avoid costly and unnecessary investments in legacy grid infrastructure that may crowd out or impede the adoption of proven, cost-effective clean energy technologies and the transition to a clean energy future.

PRINCIPLES OF GRID MODERNIZATION

The following principles support and reflect the above goals of grid modernization and should be present in some form in any proposal. These principles can be used as an initial filter and framework to assess the merits of proposed grid modernization plans, investments and initiatives.

Grid Modernization should…

1. **Support and enable policy goals, including the decarbonization of the electricity system and the beneficial electrification[1] of the transportation and building sectors.** Grid modernization proposals should support relevant policy and regulatory objectives for reducing carbon emissions and enabling the electrification of the transportation and building sectors. Grid modernization investments should take into account other incentives or programs that spur increased consumer and community adoption of DERs, such as EVs and EV fast charging, electric appliances, solar, wind, energy storage, demand response and/or energy efficiency measures. Rather than duplicate utility investments, consumer investments in DERs should be leveraged and properly accounted for in grid modernization plans, particularly as optimal alternatives to more costly grid investments.
2. **Enable the adoption and optimization of distributed energy resources (DERs).** Grid modernization investments should enable, not hinder, the adoption of DERs, which can offer economic, reliability, resilience and environmental benefits to consumers, communities and utilities.[2] Grid modernization efforts should aim to increase the transparency of the grid and improve grid modeling procedures such that consumers, local governments, developers and technology providers can support the accelerated customer adoption of DERs. In addition, concurrent with grid modernization investments and plans, efforts should be made to streamline and automate interconnection processes and reduce the overall cost of DER adoption and integration for the benefit of all ratepayers.
3. **Empower people, communities and businesses to adopt affordable clean energy technologies and clean energy solutions.** Grid modernization plans and investments should help, not hinder, consumers' ability to adopt technologies and solutions that reduce the impact of their energy usage, enable easier ways to manage energy costs, and support their carbon reduction, energy consumption and/or financial goals. In addition, all interested and vested stakeholders should have easy access to information about the grid. Grid modernization investments should help support the adoption of more streamlined processes for installing, interconnecting and integrating these technologies (without impacting grid safety and reliability).
4. **Support secure and transparent information sharing and data access.** Grid modernization plans should facilitate the increased understanding of grid needs and operations among all stakeholders, including regulators. In addition, investments should enable enhanced interoperability, improved visibility and coordinated control of the grid. Improvements in transparency should allow all parties — utilities, developers, customers, local governments, regulators and other decision-makers — to access information about the grid such that DERs and other low-carbon clean energy technologies are deployed strategically, swiftly and affordably in preferred locations on the grid.

5. **Enable innovation in technology and business models.** Grid modernization plans and investments should encourage the participation of third-party stakeholders in providing information, technologies, services, and technical and financial support to consumers. To the extent applicable and appropriate, economic development and job creation goals could also be taken into account when evaluating the merits of grid modernization plans. Non-wires alternatives (NWA) should be identified and supported as viable solutions to serve identified grid needs, ahead of traditional, more capital-intensive investments (which may lead to stranded assets or more costly infrastructure). Grid modernization plans should also address whether financial incentives, penalties and/or pilot programs are needed to address the limitation of existing utility business models to encourage consumer-based technology innovation, and particularly the underlying regulatory incentive for utilities to prioritize capital expenditures to increase their profits based on the prevalent return on investment-based business model.

In addition to the above principles, we suggest that regulators and stakeholders evaluating Grid Modernization (GridMod) plans consider the following questions in their assessments (please refer to endnotes for additional explanation).

1) Does the GridMod plan include specific, measurable goals and objectives?

- **a)** Does the plan align with and support existing state policy goals and/or commission orders?
- **b)** Is it clear what specifically the utility is trying to achieve with its plan?
- **c)** Is it clear how the utility will measure the success of the plan?

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2) Does the GridMod plan include a credible Benefit/Cost Analysis (BCA) to demonstrate the plan's cost effectiveness or cost reasonableness?

- **a)** Has the utility applied an appropriate BCA methodology (e.g., least-cost/best-fit, benefit/cost ratio, Utility or Societal Cost test, etc.) for each category of GridMod expenditures?[3]
- **b)** Does the plan include disclosure of all planned GridMod expenditures including those beyond the initial period of the request?
- **c)** Do the costs reflect the full revenue requirements and customer bill impacts over the life of the assets?[4]
- **d)** Has the utility explicitly included cost contingencies and provided a corresponding range of potential BCA results?[5]
- **e)** If the BCA includes benefits from improved reliability, are the identified benefits reasonable and credible?[6]
- **f)** Does the plan include a qualitative assessment of how it will improve resilience?[7]
- **g)** Has the utility applied an appropriate discount rate in its BCA calculations?[8]
- **h)** Has the utility provided support for its key BCA assumptions and provided a sensitivity analysis of those assumptions?[9]

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3) Does the GridMod plan include detailed metrics to track progress?

- a) Are the metrics tied to the stated goals/objectives of the plan, the BCA, and the underlying BCA assumptions?
- b) Has the utility provided baselines and targets for each metric?
- c) Has the utility defined a process for ongoing tracking and reporting of metrics including costs and benefits?

4) **Will the GridMod plan enable beneficial electrification?**

   a) Has the utility quantified and planned for the potential impact on load and demand from on-road, non-road[10] and building electrification?
   b) Are the utility's assumptions about electrification consistent with state policy goals?
   c) Does the plan reflect input from other relevant transportation and building sector programs/ agencies (e.g., public transportation office, large fleet vehicle users, state transportation agency, building codes and standards, etc.)?
   d) Has the utility identified barriers to EV adoption in its service territory, and does the plan adequately address the barriers?
   e) Does the plan include investments in the grid to accelerate EV adoption and deployment of EV charging infrastructure?
   f) Does the plan include an appropriate balance between utility ownership and private ownership of EV charging infrastructure?
   g) Will the utility offer rate structures to encourage off-peak EV charging and, if so, by when?
   h) Does the plan include programs and incentives for the electrification of space and water heating?

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5) **Is the GridMod plan a requirement and/or outcome of a credible Integrated Distribution Planning (IDP) process?[11]**

   a) Will the plan help accelerate the adoption and integration of DERs?
   b) Does the plan enable or enhance identified IDP objectives, capabilities or tools (i.e., improved load and DER forecasting, hosting capacity analyses, identification/ publication of grid needs and locational value, explicit consideration of non-utility owned DERs as non-wires alternatives (NWA) and NWA acquisition)?
   c) Will the plan result in increased transparency and understanding of distribution system data (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?

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6) **Are the GridMod plan's proposed investments based on a demonstrated need?[12]**

   a) Has the utility defined all of the capabilities[13] the plan will enable or enhance?
   b) Has the utility adequately explained how these capabilities relate to the overall goals and objectives of the plan?
   c) Has the utility provided benchmarking or other credible analysis supporting the need for the new or enhanced capabilities?

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7) **Is the GridMod plan synergistic with other existing or planned investments (e.g., Advanced Metering Infrastructure (AMI) supporting metering as well as distribution planning/operations, etc.)?**

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8) **Does the GridMod plan meaningfully reflect input from stakeholders, including consumer advocates, clean energy advocates, customers, large energy users, technology vendors, transportation interests and local governments?**

   a) Will the utility meaningfully incorporate Commission and stakeholders' input throughout the plan's design and implementation?

In addition to the above questions, the following table lists the categories of investments that may be included in a GridMod plan, along with specific examples or components in each category. The questions are intended to help evaluate the merits of the GridMod plan and may highlight the need for additional analysis and/or evidence to support proposed investments. Please refer to the Glossary for definitions of terms and acronyms, and please refer to endnotes for additional context and perspective.

Within the GridMod plan:

IF YOU SEE INVESTMENTS FOR

ADVANCED METERING

EXAMPLES OR COMPONENTS INCLUDE...

- Advanced Metering Infrastructure (AMI)[14]
- Smart Meters
- Meter Data Management System (MDMS)
- AMI Head-end System
- Mesh Network
- Backhaul Network
- Field Area Network (FAN)

THEN ASK...

- Do the benefits exceed the costs (as measured by present value of revenue requirements or bill impacts)?
  - *If not, is there a credible rationale for why the AMI investment is needed?*
- How will AMI support distribution planning/operations (e.g., load forecasting, voltage monitoring, communications with intelligent grid devices, etc.)?
- Will customers be able to download and share their usage data using a standardized format, such as Green Button data? If so, by when?
- What time-varying rates will the utility offer and by when?
  - *What are the projected energy/demand savings from the proposed rates?*
  - *Are the projections credible and based on actual results from other utilities?*
- What new AMI-enabled energy efficiency and/or demand response programs will the utility offer and by when?
  - *What are the projected energy/demand savings from these programs?*
  - *Are the projections credible and based on actual results from other utilities?*
- What other tools will the utility deploy to help customers manage energy usage, and by when?
- What plans does the utility have for customer education, and are the plans sufficient?
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR

GRID AUTOMATION AND SENSING

EXAMPLES OR COMPONENTS INCLUDE...

- Distribution Automation (DA)
- Substation Automation
- Supervisory Control and Data Acquisition (SCADA)
- Fault Location, Isolation and Service Restoration (FLISR)
- Self-Healing Grid
- Remote Fault Indicators
- Line Sensors
- Intelligent Grid Devices
- Telemetry
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is the utility claiming that the automation will improve reliability? If so:
  - *Is there a demonstrated need for the reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?*
  - *Are the projected improvements in SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) credible?*[15]
  - *Is the utility using the Interruption Cost Estimate (ICE) Calculator to quantify the benefits from improved reliability? If so:*
    - » *Are the inputs to and outputs from the ICE Calculator credible?*
    - » *Has the utility accounted for the impact of momentary interruptions?*
- What steps has the utility taken to minimize the risk of technology obsolescence?[16]
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR

OTHER RELIABILITY IMPROVEMENTS

EXAMPLES OR COMPONENTS INCLUDE...

- Grid Hardening
- Undergrounding[17]
- Voltage Conversions
- Line Rebuilds
- Battery Energy Storage Systems (BESS)
- Microgrids
- Asset Replacements
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is there a demonstrated need for reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?
- Is the utility using the ICE Calculator to quantify the benefits from improved reliability? If so:
  - *Are the inputs to and outputs from the ICE Calculator credible?*
  - *Has the utility accounted for the impact of momentary interruptions?*
- Has the utility sufficiently considered customer- and third party-owned DERs as NWA?[18]
- What steps has the utility taken to minimize the risk of technology obsolescence?[19]
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR

FOUNDATIONAL TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Load Forecasting
- DER Forecasting
- Power Flow Modeling
- Load Flow Modeling
- Fault Analysis
- Geographic Information System (GIS)
- Distribution Management System (DMS)
- Outage Management System (OMS)
- Advanced Distribution Management System (ADMS)
- Customer Information System (CIS)
- Customer Information Platform (CIP)
- Enterprise Asset Management System (EAMS)

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software (i.e., in the context of stated goals/objectives)?
- Is the utility claiming that the tools/software will improve reliability? If so, are the projected improvements measurable and credible?
- Is the utility claiming that the tools/software are needed to integrate DERs? If so, has the utility sufficiently demonstrated this need and explained how the tools/software will address this need?
- If the utility plans to use commercial-off-the-shelf (COTS) software, do the selected technologies and associated cost estimates reflect a rigorous Request for Proposals (RFP) process?[20]
- If custom software, what is the basis for the estimated costs and how do these costs compare to COTS?
- Does the utility currently have the staff and expertise to take full advantage of the software tools? If not, does the utility have an appropriate training or hiring plan?
- If COTS software is used, what steps has the utility taken to minimize the risk of technology obsolescence?[21]
- Has the utility explained how the technologies will enable or enhance IDP capabilities?
- Will the utility provide the inputs, assumptions and outputs of the tools and software in a transparent, easily understandable manner?

IF YOU SEE INVESTMENTS FOR

ADVANCED TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Distributed Energy Resources Management System (DERMS)
- Demand Response Management System (DRMS)
- Locational Net Benefit Analysis (LNBA)
- Locational Value Analysis
- Advanced Analytics
- Optimization Analytics

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software?
- Do existing and forecasted DER penetration levels warrant the need for the investment?[22]
- Are the requested tools/software commonly used by other utilities?
- If COTS software is used, are the selected technologies and associated cost estimates reflective of a rigorous RFP process?
- If custom software is used, what is the basis for the estimated costs and how do these compare to COTS?
- Will the requested tools/software enable communications with smart inverters?
- What steps has the utility taken to minimize the risk of technology obsolescence?[23]

IF YOU SEE INVESTMENTS FOR

TELECOMMUNICATIONS

- Broadband Fiber
- Broadband Microwave
- Wide Area Network (WAN)
- Field Area Network (FAN)

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Has the utility appropriately considered and incorporated public solutions (e.g., leasing lines from existing telecommunications infrastructure providers)?
- Will the proposed field area network (FAN) enable and/or support communications with advanced inverters?
- If the utility is also deploying AMI, can the AMI communications network also function as the FAN? If not, why?
- What steps has the utility taken to minimize the risk of technology obsolescence?[24]

IF YOU SEE INVESTMENTS FOR

VOLTAGE AND REACTIVE POWER MANAGEMENT

EXAMPLES OR COMPONENTS INCLUDE...

- Voltage Optimization (VO)
- Integrated Volt/VAR Control (IVVC)
- Integrated Volt/VAR Optimization (IVVO)
- Conservation Voltage Reduction (CVR)

THEN ASK...

- Has the utility appropriately considered and utilized the capabilities of advanced inverters and secondary VAR controllers?
- What are the expected peak demand and energy usage reductions, and how will the utility measure and verify the savings?
- What are the expected line loss reductions, and how will the utility measure and verify the savings?
- If the utility is also deploying AMI, how will AMI support or enhance the proposed voltage management solution?
- What steps has the utility taken to minimize the risk of technology obsolescence?[25]

IF YOU SEE INVESTMENTS FOR

DER INTEGRATION OR INTERCONNECTION

EXAMPLES OR COMPONENTS INCLUDE...

- Hosting Capacity Analysis (HCA)
- DER Interconnection Tools
- Information Sharing Portals
- Reconductoring
- Voltage Conversion
- Relay and protection upgrades or replacements
- Voltage regulator installation or replacement
- Recloser installation or replacement
- Transformer replacement
- Capacitor installation or replacement
- Upgrades to address reverse power flow

THEN ASK...

- Has the utility sufficiently demonstrated the need for the investment?
- Do existing and forecasted DER penetration levels support the need?
- Are the issues allegedly caused by DERs supported with evidence?
- Has the utility appropriately considered the capabilities of advanced inverters and secondary VAR controllers to defer or eliminate the need for the investment?
- Are state level discussions underway to adopt the The Institute of Electrical and Electronics Engineers (IEEE) *Standard 1547-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018)* for smart inverters? If so, do the assumptions in the GridMod plan reflect the impact of this new standard?
- If the utility is proposing investments in interconnection tools, how will the utility incorporate customer and developer feedback into creation/refinement of the tools?
- If the utility is proposing an HCA:
  - *Has the utility clearly defined the HCA use cases?*
  - *What HCA methodology is the utility proposing, and is it appropriate for the use cases?*
  - *Are the utility's plans for publishing HCA results sufficient?*[26]
  - *How frequently will the utility update the HCA, and is this sufficient?*
  - *How will the utility incorporate customer and developer feedback into the creation/refinement of its HCA?*
- To what extent will the investments enable sharing of distribution system information (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?

IF YOU SEE INVESTMENTS FOR

PILOT PROJECTS

EXAMPLES OR COMPONENTS INCLUDE...

- Battery Energy Storage Solutions (BESS)
- Non-Wires Alternatives
- Microgrids
- Time-of-use rates
- Managed EV Charging
- Demand Response programs

THEN ASK...

- Has the utility established clear goals and objectives for each proposed pilot? Are these aligned with the overall GridMod goals and objectives?
- Has the utility demonstrated that each pilot is designed based on lessons learned and best practices from other utilities?
- Does the plan call for cross-functional collaboration and stakeholder engagement during pilot design and implementation?
- For each pilot, is there a plan for replicating or scaling to support full deployment if successful?

ENDNOTES

[1] Beneficial electrification is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline, natural gas) with electricity in a way that reduces overall emissions and energy costs.

[2] See e.g., "Whereas many States recognize that DER, if interconnected and operated in a safe and reliable manner with uniform standards across multiple jurisdictions, can offer economic, reliability, resilience, and environmental benefits to consumers, communities and utilities." *EL-1/ERE-1 Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard IEEE 1547-2018*, Resolution Passed by National Association of Regulatory Utility Commissioners (NARUC) Board of Directors 2020 Winter Policy Summit, 12 February 2020, page 1, available at: https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7

[3] See a forthcoming Berkeley Lab report, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, by Woolf, T., B. Havumaki, D. Bhandari, M. Whited (Synapse Energy Economics) and L. Schwartz, Berkeley Lab.

[4] In addition to capital and O&M costs, the BCA should include full financing costs and taxes over the life of the assets, as measured by revenue requirements. It is also informative to understand how much typical customer bills are likely to increase or decrease as a result of the proposed GridMod investments.

[5] Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Good project management practices call for the use of cost contingencies, particularly for large, complex projects deploying new technologies over a long time period. Risks and uncertainties that could impact GridMod plan costs include, but are not limited to, unknowns related to the integration of new and legacy IT systems; equipment deployment delays due to weather or other factors; emergence of new viable technologies; new security threats or vulnerabilities; and changing legislation or regulations. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all BCA assumptions and calculations, it is important that the utility's inclusion of cost contingencies be explicit and transparent.

[6] Although the determination of reasonable and credible benefits is subjective, the GridMod plan should include clear, understandable, and verifiable data/analysis in support of claimed benefits. The ranges of benefits should be consistent with what the utility has demonstrated in pilots or with what other utilities have realized deploying similar technologies.

[7] A 2019 report written for NARUC concluded that, although DERs and other GridMod investments can offer resilience benefits, it is unclear how to determine their value. See Rickerson, Wilson, J. Gillis, M. Bulkeley, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*, Prepared by Converge Strategies for the National Association of Regulatory Utility Commissioners, April 2019, available at: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198

[8] A utility often uses its own weighted average cost of capital (WACC) as the discount rate in its BCA. However, according to the Synapse/LBNL report referenced in endnote 3, the appropriate BCA discount rate should reflect the time preference chosen by regulators on behalf of all customers (i.e., the regulatory perspective). The regulatory perspective should account for many factors, including low-cost, safe, reliable service; intergenerational equity; and other regulatory policy goals. The regulatory perspective suggests a greater emphasis on long-term impacts than what is reflected in the WACC, and that a discount rate lower than the WACC may be appropriate for the BCA. GridMod plans can use sensitivities to consider the impact of different discount rates (e.g., use the utility WACC as a high case, use a low-risk or societal discount rate as a low case)

[9] A typical GridMod plan BCA includes multiple assumptions such as future reliability improvements, equipment failure rates, customer participation in DSM programs, EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions. A sensitivity analysis also identifies the assumptions that have the most impact on the overall costs and benefits of the GridMod plan, thus highlighting the key assumptions that the utility should further validate, monitor, and report on throughout the GridMod plan implementation.

[10] Non-road electrification converts commercial and industrial equipment (such as forklifts, airport baggage handling equipment, cranes, conveyors, onshore generation for dock shipping, welding equipment, tugboats and ferries) from propane or diesel fuel to electricity.

[11] A credible IDP process includes the consideration of Commission, staff and other stakeholder input when developing the IDP framework and IDP priorities.

[12] A demonstrated need should include evidence that a proposed investment is actually necessary. Such evidence may include benchmarking results showing relatively poor performance, customer complaints, fines and/or penalties for poor performance, or other documented proof of poor or inadequate system conditions.

[13] In this context, the authors define a capability to be the combination of skills, processes and technologies required to achieve a specific outcome or objective. The U.S. Department of Energy (DOE) has defined 26 grid modernization capabilities. See pp. 43-49 of Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

[14] The authors are generally supportive of AMI but emphasize the importance of a utility taking full advantage of AMI capabilities for the benefit of its customers. For recommendations to ensure that utilities and customers realize the full value from AMI, see e.g., Gold, Rachel, C. Waters, and D. York, *Leveraging Advanced Metering Infrastructure to Save Energy*, American Council for an Energy-Efficient Economy, Report U2001, 3 January 2020, pp. 42-43, available at: https://www.aceee.org/sites/default/files/pdfs/u2001.pdf.

[15] According to the 2016 DOE report on results from the Smart Grid Investment Grant (SGIG) program, distribution automation (DA) can reduce the frequency and duration of sustained customer interruptions by 15-55%. However, p. 24 of the report cautions, "The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments." Additionally, utilities must take into account the increase in momentary interruptions for some customers when quantifying DA benefits.

[16] It is important that the utility emphasize "future proofing" the GridMod technologies and capabilities to minimize the risk of obsolescence. Selected GridMod technologies should include characteristics such as over-the-air firmware and configuration upgrades without the need for field visits or equipment replacement; use of open standards, protocols, and standard service components that are not vendor-specific; enhanced memory size to support potential future use cases; architecture for ease of integration with existing and future systems; and re(use) of standard interfaces to reduce design and development costs.

[17] Converting overhead facilities to underground is costly and almost never justified by reliability improvements alone. A 2012 Edison Electric Institute report, *Out of Sight, Out of Mind 2012 — an Updated Study of the Undergrounding of Overhead Power Lines* (available at https://www.eei.org/issuesandpolicy/electricreliability/undergrounding/Documents/UndergroundReport.pdf), shows an industry range of distribution overhead to underground conversion costs of $1-5 million per mile for urban construction, and $0.15-2 million per mile for rural construction. The report states, "Currently, no state has recommended wholesale undergrounding of their utility infrastructure. The cost of conversion has always been the insurmountable obstacle in each of these studies … Since 1999, an increasing number of state utility commissions have studied the possibility of mandating utilities to place all or part of their electrical facilities underground … The conclusion in every study, has determined that the cost to achieve the desired underground system is considerably too expensive for either the utility or the electrical customers."

[18] For example, in the recent Green Mountain Power (GMP) Bring Your Own Device (BYOD) pilot, the utility offers bill credits to customers in exchange for control of customer-owned home battery backup systems, EV chargers, and water heaters during peak periods. Participating customers in the GMP BYOD pilot with backup batteries experience improved reliability while also providing peak demand reductions to benefit all customers. See https://www.greentechmedia.com/articles/read/green-mountain-power-kept-1100-homes-lit-up-during-storm-outage.

[19] *See endnote 16.*

[20] The authors strongly recommend COTS only as utilities should not be in the business of developing custom software.

[21] *See endnote 16.*

[22] The authors believe DERMS technologies are nascent and unnecessary even with high penetrations of DERs. For example, at the end of 2018, Pacific Gas & Electric (PG&E) had 370,000 customers with rooftop solar and a total of 4,000 MW of rooftop solar distributed generation (DG), or 20% of the private rooftop DG capacity in the U.S. PG&E also was adding 5,000 new DG customers and 55 MW of new rooftop DG to its grid each month. In its 2018 general rate case application, PG&E did not request approval of a DERMS, stating that no vendor currently provides the comprehensive set of DERMS capabilities it requires. As DERMS functionality matures, PG&E determined that it should first "invest in foundational technology including improved data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system."

[23] *See endnote 16.*

[24] *See endnote 16.*

[25] *See endnote 16.*

[26] HCA results should be published via online maps illustrating the hosting capacity of each circuit line section. The maps should include quick-display boxes, allowing the viewer to easily see summary information for a given node, line section or feeder. All HCA results and underlying data should also be available for download.

GLOSSARY

ADMS (Advanced Distribution Management System) - software that integrates several operational systems to optimize distribution grid performance. ADMS components can include a distribution management system (DMS); DER management system (DERMS); outage management system (OMS); demand response management system (DRMS); fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR) and integrated Volt-VAR control (IVVC).

Advanced Inverter - a power electronics device that transforms DER direct current to alternating current. It also provides functions such as reactive power control and voltage/frequency ride-through responses to improve the stability, reliability and efficiency of the distribution system. Also known as a "smart inverter."

AMI (Advanced Metering Infrastructure) – a system that includes meters, communication networks between the meters and utility, and data collection and management systems that make the information available to the utility. AMI communications networks may also provide connectivity to other types of devices such as grid sensors, switches, and DERs.

AMI Head-end System - software that transmits and receives data, sends operational commands to smart meters, and stores interval load data from the smart meters to support customer billing.

Backhaul Network - a comunications system for transmitting large volumes of data between the AMI/field device mesh networks and the utility.

Broadband Fiber - communication systems using optical fiber that are capable of very high bandwidths.

Broadband Microwave - high frequency radio communication systems that are widely used by utilities for substation and SCADA communications.

Bring Your Own Device (BYOD) - a type of energy efficiency or demand response program involving the use of customer-owned DER devices (e.g., batteries, thermostats, etc.), and may include aggregated dispatch to provide grid services.

CAIDI (Customer Average Interruption Duration Index) – the average duration of sustained outages in a year, measured in minutes per interruption. CAIDI = SAIDI / SAIFI.

CIP (Customer Information Platform) – software for billing and revenue collection, may also include incorporation of new capabilities enabled by AMI and an MDMS.

CIS (Customer Information System) - software for billing and revenue collection.

Cost Effectiveness - determination if a proposed investment's benefits exceed the costs.

Cost Reasonableness - determination if a proposed investment represents the least-cost/best-fit solution to address a need, regardless if the benefits exceed the costs.

COTS (Commercial-Off-The-Shelf) - software products that are ready-made and available for purchase in the commercial market.

CVR (Conservation Voltage Reduction) - intentional reduction of voltage within established limits to achieve demand reduction and energy savings for customers.

DA (Distribution Automation) - technologies including sensors, communication networks, and switches, through which a utility can improve the operational efficiency of its distribution system.

DERs (Distributed Energy Resources) - energy resources connected to the distribution system that include distributed wind and solar generation, combined heat and power, energy storage, electric vehicles, energy efficiency, demand response and microgrids.

DERMS (Distributed Energy Resources Management System) - software that provides distribution operators near real-time visibility into and control of individual DERs or DER aggregations.

DMS (Distribution Management System) - software capable of collecting, displaying and analyzing near real-time electric distribution system information. A DMS can interface with other operations applications, such as a GIS, OMS, and CIS to create an integrated view of distribution operations.

DR (Demand Response) - voluntary (and compensated) load reduction used by utilities as a system reliability or local distribution capacity resource. Demand response allows utilities to cycle certain customer loads on and off in exchange for financial incentives.

DRMS (Demand Response Management System) - software to administer and operationalize DR aggregations and other DR programs.

EAMS (Enterprise Asset Management System) - software for collecting attributes and analysis of distribution grid assets.

FAN (Field Area Network) - the communications network between distribution substations and grid devices (such as switches, sensors and AMI meters) on the distribution system.

FLISR (Fault Location, Isolation and Service Restoration) - a combination of hardware and software technologies that identify the location on a circuit where a fault has occurred, isolate the faulted line segment and restore service to all customers not connected to the faulted line segment. FLISR is also called a Self-Healing Grid.

GIS (Geographic Information System) - as defined in the context of the electric distribution system, software containing attributes of distribution grid assets and their geographic locations to enable presentation on a map. GIS may also serve as the system of record for electrical connectivity of the assets.

Green Button – an industry standard for making detailed customer energy-usage information available for download in a simple, common format.

Grid Hardening - grid improvements such as rebuilding portions of distribution circuits or proactively replacing assets to improve reliability and resilience.

Hosting Capacity - the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

HCA (Hosting Capacity Analysis) - the calculation and publication of the distribution system's hosting capacity.

ICE (Interruption Cost Estimate) Calculator – an online tool for quantifying the economic impact to customers from improved reliability. See https://icecalculator.com/home.

IDP (Integrated Distribution Planning) - proactive planning for DERs growth consisting of four principal components: (1) mapping circuits' hosting capacity; (2) forecasting the expected growth of DERs on each circuit; (3) prioritizing grid upgrades to integrate DERs and (4) proactively pursuing grid upgrades (including traditional capital upgrades as well as DERs themselves) to meet anticipated grid needs.

Intelligent Grid Devices – devices such as switches and sensors that provide situational awareness, grid control capability and enable two-way communications.

IVVC (Integrated Volt/VAR Control) - a process of controlling voltage and reactive power flow on the distribution system to improve overall system performance, allowing a utility to reduce electrical losses, eliminate voltage profile problems and reduce electrical demand.

Line Loss - A natural occurrence of power delivery systems, consisting mainly of power dissipation in system components. The largest component of losses is caused by the electrical resistance of equipment and is proportional to the square of the current. As system load or current increases, system components lose more energy in the form of heat, and losses increase exponentially. Losses are therefore greatest during peak loading periods.

MAIFI (Momentary Average Interruption Frequency Index) – the average number of momentary interruptions experienced by customers in a year.

MDMS (Meter Data Management System) – a software platform that processes and stores AMI interval data used for billing.

Mesh Network - a wireless method of communication in which information is transmitted through a network of transmitters/receivers en route to its final destination.

Microgrid - a group of interconnected loads and DERs able to operate when connected to the larger distribution grid and also able to operate as an "island" when there is an outage or other grid disturbance.

Momentary Interruptions – according to IEEE, momentary interruptions are outages lasting less than 5 minutes. Momentary interruptions are not included in the standard reliability indices of SAIDI, SAIFI, and CAIDI.

NWA (Non-Wires Alternative) – the deployment of DERs or combinations of DERs — owned by the utility, customers or other third parties — to defer or avoid the need for investment in conventional, more costly grid infrastructure. Also referred to as a Non-Wires Solution.

OMS (Outage Management System) - software to enable the efficient and safe restoration of outages, as well as communications with customers regarding restoration status. An OMS can serve as the system of record for the as-operated distribution connectivity model, as can the DMS or ADMS.

Reclosers - devices that, when sensing a fault, temporarily interrupt power downstream from their location and then automatically reclose and restore power if the fault has cleared.

Reconductoring - replacing existing conductor with larger conductor to address a thermal or voltage issue.

SAIDI (System Average Interruption Duration Index) - the average duration of sustained outages experienced per customer in a year, measured in minutes per customer. SAIDI = CAIDI x SAIFI.

SAIFI (System Average Interruption Frequency Index) - the average number of sustained outages experienced per customer in a year, measured in interruptions per customer. SAIFI = SAIDI / CAIDI.

SCADA (Supervisory Control and Data Acquisition) - a system of remote controls and telemetry to monitor and control the transmission and distribution system.

Secondary VAR Controllers - devices installed on the low-voltage side of distribution transformers to assist in controlling reactive power and voltage.

Self-Healing Grid - *see FLISR*

Smart Meter - a device capable of two-way communications used for measuring electricity consumption and other end-use information and transmitting this information on demand to a central location. Smart meters provide near real-time customer usage data, as well as interface with other 'smart' devices in the home or business.

Sustained Interruptions - according to IEEE, sustained interruptions are outages lasting more than five minutes.

Telemetry - the automatic measurement and wireless transmission of data from remote sources.

Undergrounding - conversion of existing overhead distribution facilities to underground for improved aesthetics or to address reliability issues.

Voltage Conversion - increasing the voltage of a distribution circuit (e.g., from 4kV to 12kV) to increase its capacity to serve load or to accommodate DERs.

VAR (Volt Ampere Reactive) – a measure of reactive power. Reactive power energizes the magnetic field of alternating current power system components but does no actual work, and represents the component of the current that is out of sync with the voltage.

VO (Voltage Optimization) - a combination of CVR and IVVC, resulting in optimal flow of reactive power, reduced line losses, and reduced customer demand and energy consumption.

VVO (Volt-Var Optimization) - *see VO.*

WAN (Wide Area Network) - the communications network connecting distribution substations with operations/control centers and other utility facilities.

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Synapse, Tim Woolf, Presentation to the Michigan PSC on August 14, 2019. Available at https://www.michigan.gov/documents/mpsc/Aug_14_Presentations_663481_7.pdf The presentation is based on a forthcoming Berkeley Lab report, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, by Woolf, T., B. Havumaki, D. Bhandari, M. Whited (Synapse Energy Economics) and L. Schwartz, Berkeley Lab.

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Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations

February 2021

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This report is intended to be used in conjunction with U.S. Department of Energy's Modern Distribution Grid.

Summary

A central objective of utility grid modernization plans is to demonstrate that investments will provide net benefits to utility customers. The plans typically include some form of benefit-cost analysis (BCA) to determine whether projected benefits of grid modernization investments exceed estimated costs.

For jurisdictional utilities, grid modernization plans pose some new and complex challenges for state public utility commissions in determining whether projects will provide net benefits to customers. Plans typically include multiple grid modernization components that have interactive effects and are difficult to analyze or justify separately. Many benefits are hard to quantify or monetize, making it difficult to compare all benefits and costs. Part of the rationale for some grid modernization investments is to meet state energy goals, which can be difficult to quantify and account for in BCA. Equity issues arise when investments may benefit some types of customers more than others.

This report provides state public utility commissions, energy offices, utility consumer representatives, and other stakeholders with a framework for navigating BCA for utility grid modernization plans and for supporting training for these audiences on this topic. It does not attempt to explain all the complexities and details of how to prepare BCA for grid modernization plans. Instead, it presents trends, challenges, and considerations for reviewing plans.

Trends in Recent Grid Modernization Plans

We reviewed 21 recent utility grid modernization plans and found a wide variety in assumptions, methodologies, justifications, and documentation for BCA. Many of the plans did not include all information or analysis needed for a thorough regulatory review of grid modernization projects. Following are some of the key items that were lacking in the plans:

- An overarching rationale for grid modernization investments and an explanation of how individual components will help meet overall goals
- Identification of cost-effectiveness test(s) used
- Identification of discount rate(s) used to determine present values
- Methodologies to account for interdependencies of grid modernization components
- Methodologies to account for unmonetized benefits of grid modernization components
- Robust definitions of grid modernization metrics and how they will be used to monitor grid modernization benefits over time
- Methodologies or discussions of how to address any customer equity issues

Challenges and Potential Approaches

Several aspects of planning for utility-facing investments in grid modernization make BCA more challenging than for other utility investments. The following table summarizes these challenges and potential approaches for addressing them.

Challenge	Potential Approaches
Identifying objectives	• Use long-term strategic planning to define objectives upfront • Identify the amount and type of cost-effective DERs
Documenting the purpose of each grid modernization component	• Specify a standard taxonomy for grid modernization • Define purpose and driver of each grid modernization component
Determining when to apply least-cost, best-fit approach	• Consider grid modernization objectives • Consider purpose and driver of the component • Consider whether component is core or application
Choosing BCA framework	• Articulate the BCA framework upfront • Focus on two tests: Utility Cost test and Regulatory test
Choosing discount rate(s)	• Choose a discount rate that reflects state regulatory goals • Conduct sensitivities using different discount rates
Accounting for interactive effects	• Use the least-cost, best-fit approach where warranted • Use scenario analysis with different combinations of components • Conduct BCA for grid modernization components in isolation
Accounting for benefits that are hard to quantify or monetize	• Use the least-cost, best-fit approach where warranted • Establish metrics to assess the extent of benefits • Apply methodologies to make unmonetized benefits transparent
Addressing uncertainty	• Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling
Putting BCA results in context	• Estimate long-term bill impacts
Prioritizing grid modernization investments	• Identify least-regrets investments that balance cost, risk, and functionality and value
Encouraging follow-through	• Establish metrics to monitor achievement of benefits

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NOTE: Information in this report reflects completion in October 2019.

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1.0 Introduction

In recent years, many electric utilities have prepared grid modernization plans for review by state public utility commissions.[1] A central objective of these plans is to demonstrate that grid modernization investments will provide net benefits to customers.[2] The plans typically include some form of benefit-cost analysis (BCA) to determine whether benefits of grid modernization projects will exceed costs.

Some of the key challenges for states determining whether investments will provide net benefits to customers include the following:

- Multiple grid modernization components with interactive effects are difficult to analyze or justify separately.
- Many benefits are hard to monetize, making it difficult to compare them with costs using a single metric.
- Equity issues may arise when all customers pay for grid modernization projects, but benefits of a particular project may accrue more to some customers than others.
- Utilities seek some form of approval for grid modernization projects before making investments.

Considerable progress has been made in recent years to support BCA of utility grid modernization plans. This work includes taxonomies for categorizing key aspects of grid modernization technologies and components and new evaluation approaches.[3] However, regulatory review practices have not kept pace.

This report provides state public utility commissions, energy offices, utility consumer representatives, and other stakeholders with a framework for navigating BCA for utility grid modernization plans, and it supports training for these audiences on this topic. It does not attempt to explain all of the complexities and details of how to prepare BCA for grid modernization plans. Instead, it presents trends, challenges, and considerations for reviewing plans. It includes a brief review of 21 recent utility grid modernization plans and identifies how to address several of the most challenging issues when reviewing them.

The report also builds on some of the key concepts in U.S. Department of Energy's forthcoming *Modern Distribution Grid Guidebook*, which synthesizes and updates elements of its Modern Distribution Grid Decision Guide.[4]

While this report emphasizes utility-facing grid modernization projects, the principles and concepts presented here generally apply to all types of grid modernization projects.

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[1] For most plans we reviewed, the grid modernization investments had not yet been made, and the utilities were seeking some form of guidance or approval from the state public utility commission. The issues discussed in this report are relevant even if the utility's filing with the commission is for cost recovery of grid modernization investments already made (no longer just a "plan").

[2] Other key objectives are meeting state energy goals and serving the public interest.

[3] See, for example, GMLC 2017; GMLC 2019; US DOE 2017; DOE Guidebook.

[4] DOE 2017, Volumes I, II, and III.

This report provides an overview of the challenges and some options for addressing them.

- Section 2 summarizes utility-facing grid modernization technologies and related issues.
- Section 3 presents BCA considerations and challenges related to grid modernization.
- Section 4 describes recent trends in BCA based on review of 21 grid modernization plans.
- Section 5 provides options for addressing some key challenges of these analyses.
- Section 6 summarizes the process that public utility commissions can use to provide utilities with guidance on grid modernization BCA, as well as the process that utilities can use to prepare BCA that address some of the challenges described in this report.

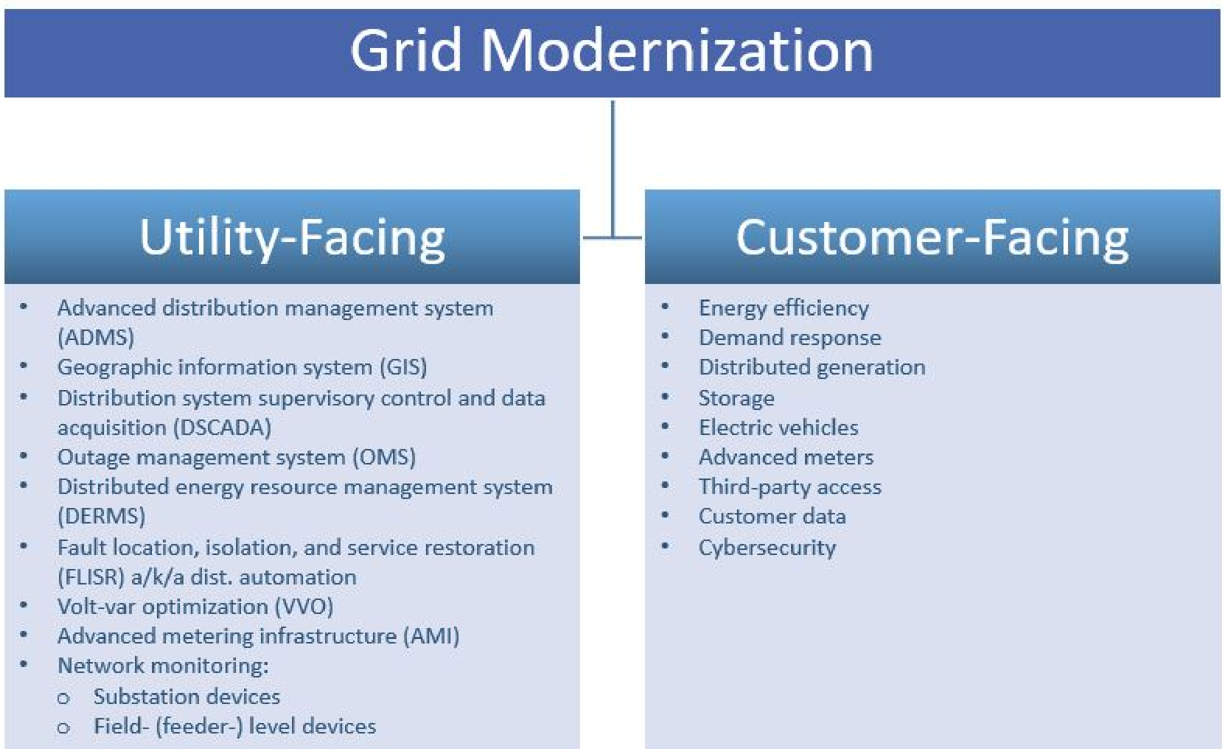
2.0 Utility-Facing Grid Modernization

Utility-Facing Versus Customer-Facing Grid Modernization

Utilities include many different components in their grid modernization plans and combine them in different ways. *Utility-facing* grid modernization initiatives include technologies and projects that help support more efficient and effective operation of distribution and transmission systems, including improved reliability and resilience. *Customer-facing* grid modernization initiatives include technologies that help support customer adoption of distributed energy resources (DERs) and customer access to third-party service providers and markets.

Figure 1 summarizes these two types of components.

Figure 1. Utility-Facing and Customer-Facing Grid Modernization Components[5]



This report focuses on conducting BCA for utility-facing projects. However, many of the principles and concepts described in this report are relevant to customer-facing grid modernization projects as well.

Key Costs and Benefits of Utility Grid Modernization

Table 1 and Table 2 provide examples of the types of costs and benefits associated with grid modernization plans. The list of costs and benefits comes from our review of utility-facing grid modernization plans, discussed in detail in Section 4.

5 Some grid modernization components may be either utility- or customer-facing, depending on the context. Several categories of DERs, for example, may be owned by the customer (behind the meter) or by the utility (in front of the meter).

The tables categorize costs and benefits according to whether they apply to the utility system or to society in general.

- The costs and benefits for the "utility system" are those impacts on the entire utility system used to provide electricity services to retail electricity customers.[6] The utility system includes all elements of electricity services—generation, transmission, and distribution—regardless of whether the utility is vertically integrated or distribution only.

- The costs and benefits for "society" are those impacts experienced by society in general, not just customers of the electric utility.

Breaking out grid modernization costs and benefits in this way provides public utility commissions with useful information on implications of grid modernization for utility customers. Costs and benefits to the utility system indicate impacts on electric utility customers in terms of bills and services they receive, while costs and benefits to society indicate how well grid modernization projects are likely to meet additional state goals.

Table 1. Examples of Costs for Utility-Facing Grid Modernization

Cost	Utility System	Society
Incremental utility operations and maintenance (O&M) costs	✓	-
Incremental utility capital costs	✓	-
Incremental transmission and distribution (T&D) costs	✓	-

[6] NSPM 2017, Section 3.2

Table 2. Examples of Benefits for Utility-Facing Grid Modernization

Benefit	Utility System	Society
Reduced O&M costs	✓	✓
Reduced generation capacity costs	✓	✓
Reduced energy costs	✓	✓
Reduced T&D costs	✓	✓
Reduced T&D losses	✓	✓
Reduced ancillary services costs	✓	✓
Increased system reliability	✓	✓
Increased safety	✓	✓
Increased resilience	✓	✓
Increased DER integration	✓	✓
Improved power quality	✓	✓
Reduced customer outages	✓	✓
Increased customer satisfaction	✓	✓
Increased customer flexibility and choice	✓	✓
Reduced environmental compliance costs	✓	✓
Other environmental benefits	-	✓
Economic development benefits	-	✓

"Increased DER integration" is included in this table because it is frequently cited by utilities as a benefit of grid modernization. However, this benefit is distinctly different from the other benefits listed. Increased DER integration is more akin to an impact that will have its own costs and its own benefits, many of which already are listed in Table 1 and Table 2.[7]

Costs and benefits presented in these tables are not exhaustive. Examples of additional costs might include those for incremental metering, data management, and program administration. Examples of additional benefits are reduced ancillary service costs and wholesale market price suppression impacts.[8]

The lists of costs and benefits in these tables reveal important considerations for grid modernization BCA. First, the set of costs is generally narrower, simpler to define, and easier to calculate than the set of benefits. Consequently, many grid modernization plans include a relatively complete and detailed set of costs.

Second, grid modernization costs are typically incurred by all utility customers, while some benefits accrue only to society. In addition, in some cases benefits accrue to only specific customers. That makes it challenging to determine how much all utility customers should be expected to pay for those benefits.

[7] Some DERs also have participant costs and benefits, some of which can be quite large. Utility-facing grid modernization investments, on the other hand, typically do not have direct participant costs or benefits.

[8] See, for example, DOE Guidebook.

Third, many of the benefits are difficult to put into monetary terms. For example, utilities, state public utility commissions, and other stakeholders have had difficulty monetizing benefits such as resilience, safety, customer flexibility and choice, and improved power quality. While progress has been made in recent years to establish metrics and develop methodologies for quantifying and monetizing these benefits, most BCAs include some of these benefits in qualitative terms only.

Fourth, many costs and benefits cannot be easily identified separately for each grid modernization component. As described below, many components are interdependent, and in many cases benefits of one component cannot be experienced in the absence of others.

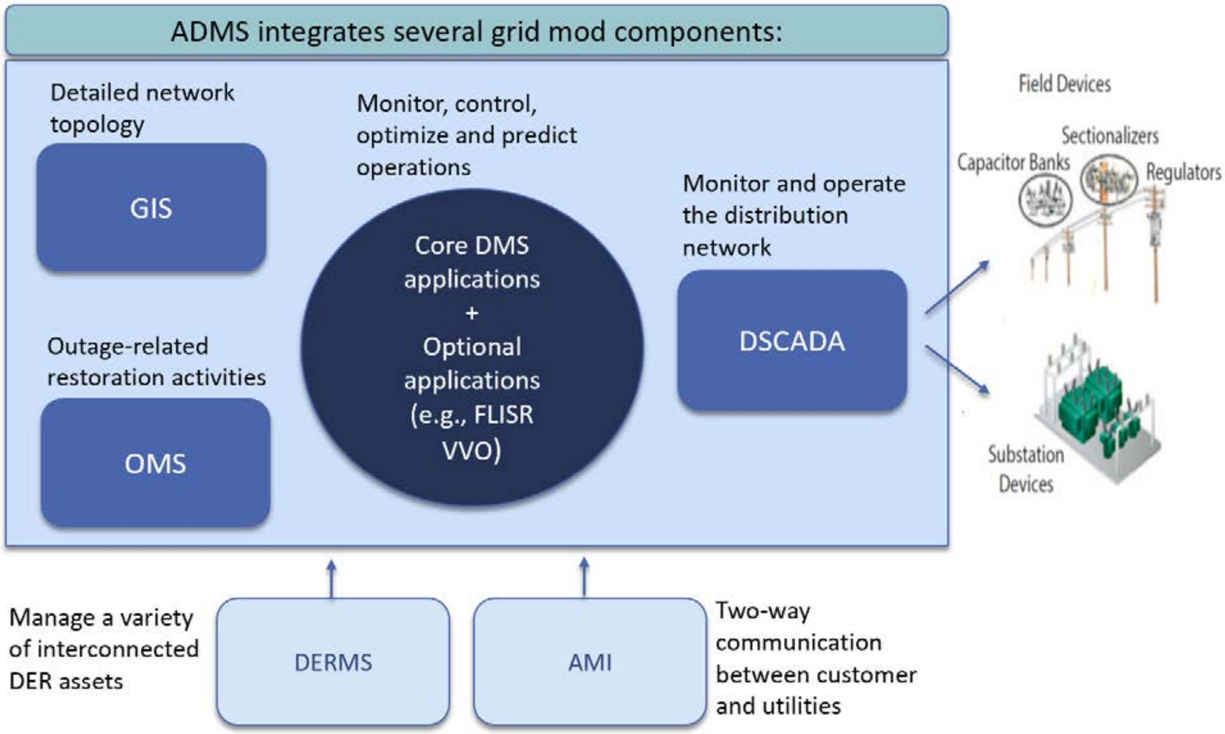
Fifth, some benefits are not well defined in utility grid modernization plans. For example, many plans list increased DER integration as one of the most important benefits of utility-facing grid modernization. However, the plans we reviewed did not provide quantitative information about increased DERs that are likely to be installed as a result of grid modernization. Further, this benefit was typically not put into monetary terms. Instead, it was addressed with qualitative statements, even though increased DER integration was one of the primary justifications for utility-facing grid modernization components. A fully transparent and comprehensive grid modernization BCA would provide more quantitative data on the likely increase in DERs. This is especially important if one of the key objectives of the proposed grid modernization components is to enable DERs. Such BCA would start with reasonable forecasts of the type and magnitude (units and capacity) of incremental DERs to be installed during the BCA study period. Ideally, it also would include the costs and benefits (e.g., resilience) associated with those incremental DERs, presented separately from costs and benefits of utility-facing grid modernization components.

Interdependency of Grid Modernization Components

One of the most difficult challenges of reviewing the cost-effectiveness of utility-facing grid modernization proposals is that many of the components are interdependent: The costs and benefits of one grid modernization component may be highly dependent upon the performance of other components. For example, Advanced Distribution Management Systems (ADMS) integrate and enable several other grid modernization components and cannot be easily separated from those other components for cost-effectiveness analysis. Figure 2 illustrates the interdependent relationship between ADMS and other grid modernization components.

Figure 2. Advanced Distribution Management Systems (ADMS) Integrates and Enables Many Grid Modernization Components

Source: Adapted from World Bank 2017, page 24.



Unmonetized Benefits

Unmonetized benefits create challenges for any type of BCA. That is especially the case for grid modernization BCA because many of the purported benefits are hard to monetize, but they are sometimes the primary justification for the grid modernization projects. For example, reliability, resilience, customer opportunities, and DER integration are often cited as benefits of grid modernization projects, but these benefits may be difficult to put into monetary terms.

In many instances utility-facing grid modernization investments are required either for safety, reliability, or policy requirements. In such cases, it may not be necessary or worth the effort to monetize the benefits. The investments could be justified on the grounds that they are needed to meet regulatory objectives, eliminating the need to show that monetized benefits exceed monetized costs. Similarly, there are many instances where utility-facing grid modernization investments are needed to support or enable other utility investments.

Taxonomy of Grid Modernization Terms

The DOE Guidebook includes a taxonomy of terms to define and clarify the many different components of grid modernization planning, as well as a taxonomy framework to connect the objectives of grid modernization with the proposed technologies.

Table 3 presents the DOE framework and an example application.[9] The framework includes four elements: objectives, capabilities, functionalities, and technologies. Drilling down to a specific technology, such as a Meter Data Management System (MDMS), the framework indicates how the capabilities and functions that the MDMS would support can be used to meet the objective of promoting customer choice.

In addition, this framework demonstrates how metrics can be used to help ensure that grid modernization investments deliver their purported benefits. In this example, a metric indicating "online customer access to relevant and timely information" would indicate how well the proposed technologies will meet that objective over time.

Table 3. Example of DOE Taxonomy Framework

Source: Reproduced from DOE Guidebook, page 42.

Objective	Capability	Function	Technology
Customer Choice through information access for small business & residential customers to support decision-making by 2020	Provide online customer access to relevant & timely information	Remote meter data collection & verification Customer data management Energy management & DER purchase analysis	Customer Portal Customer Analytic Tools Greenbutton Smart Meter Telecommunications Meter Data Management System Customer Info System Data Warehouse

Core Components Versus Applications

The DOE Guidebook also makes an important distinction between two types of grid modernization investments:

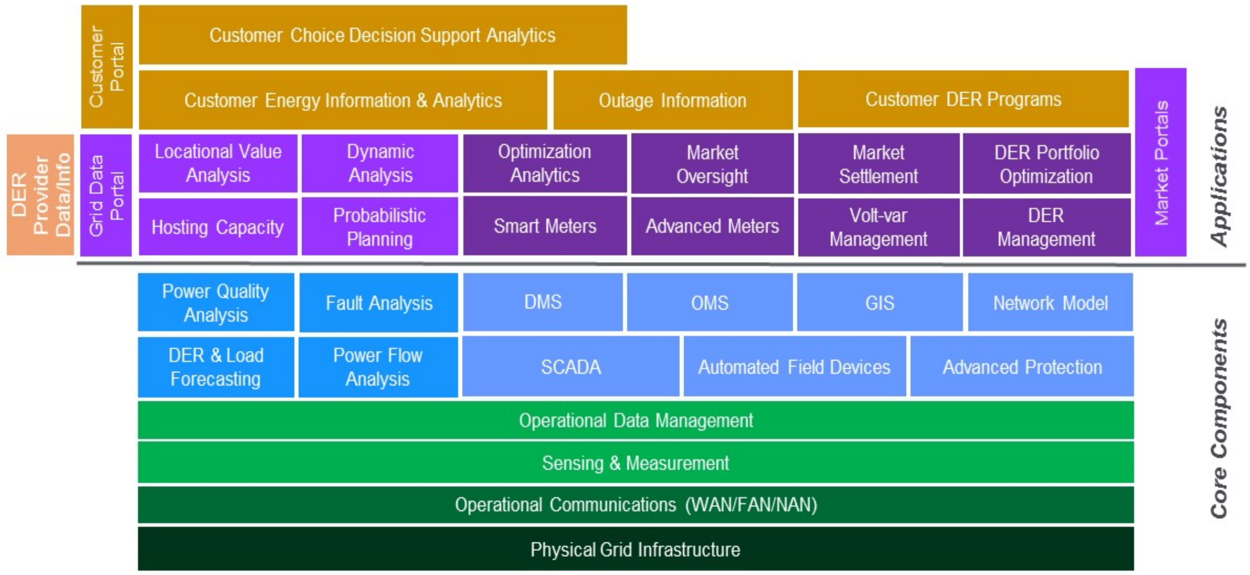
- *Core, or platform, components* represent foundational components that are necessary for providing the services required of modern grids.
- *Applications, or modules,* represent additional, single-purpose components that can be layered on top of the platform components to provide additional functionality that is desired or needed.

Figure 3 illustrates types of grid modernization investments that are considered core (platform) components and those that are considered application (modular) components. This distinction is critical for grid modernization BCA because platform components can be evaluated using a different BCA approach than application components.

[9] DOE 2017, Volume I; US DOE 2019.

Figure 3. Grid Modernization: Platform Components Versus Applications

Source: DOE Guidebook, Figure 46, page 60.



Core components are similar to traditional distribution investments that utilities make to ensure reliability. For traditional utility investments, the need is typically established upfront based on reliability requirements and other objectives, and utilities conduct economic analyses to fulfill that need with the most appropriate infrastructure at the lowest cost. In the case of core grid modernization components, the analysis is more complex because there are often additional objectives for the investments, such as resilience and integration of DERs.

On the other hand, application components are more akin to supply-side and demand-side resource decisions where utilities use economic analyses to determine whether to make those investments. In the case of grid modernization applications, the analysis is made more complex because of objectives beyond simply meeting energy and capacity needs.

For most utilities, the core components make up the majority of the projects and the costs of grid modernization plans.[10]

Section 3.0 further addresses this important distinction between platform and application components.

[10] DOE Guidebook, page 90.

3.0 Benefit-Cost Analysis Considerations

Regulatory Contexts for Benefit-Cost Analyses

Public utility commissions have used BCA for many years to make decisions on a variety of utility investments. For the purpose of reviewing grid modernization investments, BCA is typically applied in two general types of regulatory contexts:

1. **A request for approval of grid modernization plans *prior* to incurring grid modernization costs**. Such a request typically occurs in a separate docket dedicated to the review of the grid modernization proposal, allowing regulators and stakeholders an opportunity to dig into the details of the proposal. Sometimes these proposals are requested by state legislatures or public utility commissions, and sometimes they are initiated by utilities. For states that allow an *ex ante* approach, utilities may be able to request some form of preapproval of the proposed investments. Preapproval is sometimes requested for large costs that are beyond those normally included in utility revenue requirements. The ability to request preapproval, and implications for utility cost recovery, varies by state. In general, if public utility commissions provide some form of preapproval of grid modernization investments, the utilities are still required to act prudently in the execution of the grid modernization plan.

2. **A request for approval of grid modernization investments *after* incurring the grid modernization costs**. This type of request is typically made in a rate case. In this context, regulators could review whether grid modernization investments are likely to be prudent, as with other major utility investments in a rate case. One advantage of this approach is that it allows regulators to review grid modernization investments in the context of other costs and cost savings included in utility revenue requirements in the rate case. One disadvantage of this approach is that regulators may not have a chance to provide input on grid modernization principles, objectives, or the BCA methodology until after the investments have been made.[11] Another disadvantage is that the investments are reviewed alongside all the other issues in a rate case. This limits the amount of time that can be spent examining grid modernization investments, which can be complex and time consuming.

Basic Principles of Benefit-Cost Analysis

Utilities use a variety of assumptions, methodologies, and frameworks in conducting BCA. In some cases, differences may be due to different direction provided by each state. In other cases, the state may not provide guidance at all, and utilities use their own approach.

Several recent efforts have made progress toward developing a consistent set of principles to ensure that BCAs are sound, consistent with fundamental economic concepts, and provide results that are reasonable, meaningful, and can be easily interpreted by state regulators and other stakeholders. Table 4 presents a summary of BCA principles proposed in three recent initiatives: the *National Standard Practice Manual* (NSPM), DOE's *Modern Distribution Grid* (DOE) and the New York Public Service Commission's *Order Establishing the Benefit Cost Analysis Framework* (NY PSC). While some of these principles were established in the context of energy efficiency BCA, they apply to utility BCA in general and provide a foundation for the grid modernization BCA discussion in this report.

[11] This challenge can be addressed by holding a generic proceeding upfront that outlines principles and objectives of grid modernization investments and how investments will be evaluated.

Table 4. BCA Principles Proposed in Recent Initiatives

Sources: NSPM 2017; DOE 2017, volume III; NY PSC 2016.

Principle	National Standard Practice Manual	DOE Modern Distribution Grid	New York Reforming the Energy Vision
Assess alternative projects comparably with traditional options	✓	✓	✓
Account for state regulatory and policy goals	✓	✓	-
Account for all relevant costs and benefits, including hard-to-monetize	✓	✓	-
Ensure symmetry across relevant costs and benefits	✓	-	-
Apply full life-cycle analysis	✓	✓	✓
Apply incremental, forward-looking analysis[12]	✓	-	-
Ensure transparency	✓	✓	✓
Avoid combining or conflating different costs and benefits	-	-	✓
Assess bundles and portfolios instead of separate measures	✓	✓	-
Address locational and temporal values	-	✓	✓

Benefit-Cost Analysis Frameworks

Utilities and public utility commissions typically establish a BCA *framework* to analyze costs and benefits of many types of utility investments. These frameworks generally address two questions: Which costs and benefits should be accounted for in the BCA? What are the implications of those costs and benefits from the perspectives of utility customers, meeting state energy goals, and society?

Once a BCA framework is established, it is used to compare all relevant costs to all relevant benefits forecast for the study period. The study period is generally at least as long as the operating life of the investment or resource that is the subject of the analysis. Costs and benefits are converted to present values, which are then cumulated for the entire study period. The two bottom-line metrics of the BCA framework are:

- *Net benefits*, which are equal to the cumulative present value of benefits minus the cumulative present value of costs. If net benefits are positive, the investment or resource is deemed to be cost-effective.

- *Benefit-cost ratio*, which is the ratio of cumulative present value of benefits to the cumulative present value of costs. If the benefit-cost ratio exceeds 1.0, the investment or resource is deemed to be cost-effective.

[12] Incremental forward-looking analysis refers to the practice of capturing the difference between costs that would occur over the life of the subject investment as compared to the costs that would occur absent the investments. According to the forward-looking aspect of this principle, sunk costs and lost revenues should not be included in a benefit-cost analysis.

Both metrics are important when assessing cost-effectiveness because they provide information in slightly different ways. Net benefits indicate the magnitude of benefits in terms of dollars. The benefit-cost ratio indicates whether benefits will exceed costs and by what proportion.

Traditional Cost-Effectiveness Frameworks for Energy Efficiency

For many years regulators and utilities have relied upon five frameworks (often referred to as "tests") for determining the cost-effectiveness of energy efficiency resources funded by utility customers:[13]

> The *Utility Cost test* represents the perspective of the utility system. In this context, the "utility system" refers to the entire utility system used to provide electricity services to retail electricity customers, including generation, transmission, and distribution of electricity services.
>
> The *Participant test* represents the perspective of energy efficiency program participants.
>
> The *Total Resource Cost (TRC) test* represents the perspective of the utility system and efficiency program participants.
>
> The *Societal Cost test* represents the perspective of society as a whole.
>
> The *Rate Impact Measure test* presents information about the impact on rates from the efficiency programs.

For energy efficiency BCA, most states use some form of the TRC test as the primary test, many states use the Utility Cost test, and several apply the Societal Cost test.[14] Many states also consider the results of multiple tests when reviewing energy efficiency programs. Regardless of which test is used, it is important to understand what information these different tests do—and do not—provide, because the choice of test has significant implications for what investments and resources are deemed cost-effective.

These BCA frameworks that have been applied to energy efficiency resources have important implications for grid modernization BCA. Many utilities and public utility commissions are using these tests, or variations of them, for grid modernization BCA.

The National Standard Practice Manual for Energy Efficiency

The National Standard Practice Manual (NSPM) updates and expands upon traditional energy efficiency cost-effectiveness frameworks. It provides the following new concepts and insights:

- A state's cost-effectiveness tests should adhere to fundamental BCA principles.[15] Table 4 (in Section 3) presents BCA principles recommended in the NSPM.

- A state does not need to be confined to the traditional BCA tests (e.g., Utility, TRC, and Societal tests) when assessing resource cost-effectiveness. States can develop alternative tests that adhere to fundamental BCA principles.

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[13] CA PUC 2001. National Action Plan for Energy Efficiency 2008, Section 2.2.

[14] Some states calculate the results of the Participant and RIM tests as part of the cost-effectiveness analyses but do not use these tests as the primary test.

[15] NSPM 2017, pages 9-14.

- The NSPM introduces a new perspective for determining the costs and benefits to include in a BCA framework: the *regulatory perspective.* This perspective reflects the priorities and the responsibilities of regulators, where that term is applied broadly to include public utility commissioners and others.[16] The regulatory perspective should balance interests of customers and utilities and account for state energy goals. This perspective is typically broader than the utility system perspective but narrower than the societal perspective.

- While many states apply multiple cost-effectiveness tests, most states use a *primary* test to make the ultimate decision of which energy efficiency resources warrant ratepayer funding. The NSPM recommends that a state's primary cost-effectiveness test reflect the state's regulatory goals.[17] In this document we refer to a state's primary test as the *Regulatory test*.[18]

- The NSPM introduces a framework that offers a step-by-step approach for a state to establish or modify its primary energy efficiency BCA test.[19]

- Since the costs and benefits included in the Regulatory test are based on a state's energy goals, the impacts included in this test might vary from one state to another.

- States can also use *secondary* tests to inform energy efficiency cost-effectiveness decisions—for example, the Utility Cost or Societal Cost test.[20]

While the NSPM is focused on energy efficiency BCA, the principles and concepts in the NSPM are also directly relevant to BCA for grid modernization and DERs.[21] The National Efficiency Screening Project is currently developing the National Standard Practice Manual for Distributed Energy Resources, which will build on the principles and concepts of the NSPM and apply them to BCA issues that are unique to demand response, distributed generation, storage, electric vehicles, and non-wires alternatives.

Least-Cost, Best-Fit Analysis

The least-cost, best-fit approach is an economic evaluation technique that is sometimes used as an alternative to BCAs. The least-cost, best fit approach is applied when the need for a particular project or investment is already established. Once the need is established, the next step is to identify the technology option(s) that are likely to be the best fit to meet that need to achieve predetermined objectives. The final step is to identify the lowest cost way of implementing the technology chosen, typically using a competitive procurement process.

The least-cost, best-fit approach is distinctly different from a traditional BCA approach because it does not require a demonstration that monetized benefits exceed monetized costs. Instead, there is a presumption that the investment is needed, and the main goal of the economic analysis is to best meet that need at the lowest cost. This approach eliminates the need to monetize all the benefits associated with the investment in question. Instead, the least-cost, best-fit approach requires a demonstration that the investment will be needed to meet regulatory objectives.

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16 In other contexts, boards of publicly owned utilities, municipal utilities, and rural electric cooperatives.
17 NSPM 2017, page 16.
18 The NSPM refers to the primary BCA test developed using this framework as the *Resource Value* test. In this document we refer to the primary test that reflects the regulatory perspective as the *Regulatory test* because that term is more descriptive of the perspective and purpose of the test. NSPM 2017, page viii and page 11.
19 NSPM 2017, pages 18-38.
20 NSPM 2017, pages 44-46.
21 NSPM 2017, page xiii.

The least-cost, best-fit approach has been used for many years by utilities to help make decisions regarding traditional distribution investments, where the need for the distribution investments has been primarily driven by reliability and safety requirements. Grid modernization investments, however, are more challenging than traditional distribution investments because it is much less clear whether a particular grid modernization investment is needed. This makes it much less clear whether the least-cost, best-fit approach is appropriate to justify the investment.

DOE Guidebook

The DOE Guidebook provides guidance for assessing the economics of grid modernization investments from a broad, long-term perspective. It describes the importance of strategic planning, defining objectives, identifying the types and drivers of investments, prioritizing investments, using pilot programs, sequencing investments, and applying spending caps. Noting that "there is no single standard or method for determining the cost-effectiveness or prudence of grid modernization investments" in every jurisdiction,[22] the Guidebook offers a framework that can be tailored to each jurisdiction's objectives, priorities, spending limits, and industry structure.

The DOE Guidebook emphasizes ongoing, long-term utility planning processes. These can take many forms or incorporate many elements, including distribution planning, transmission planning, integrated resource planning (IRP), DER planning, and reliability and resilience planning.[23] The grid modernization planning process should be used to identify the mission and principles, develop objectives, identify grid capabilities and needed functionality, identify grid architecture, and develop strategies for the timing and coordination of grid modernization investments.[24]

Clearly identifying objectives is a critical aspect of the economic analysis of grid modernization investments. Grid modernization objectives provide the link between the investments and their expected benefits.[25] Identifying this link is especially important in the context of grid modernization, where many of the benefits are hard to monetize. Consider an example where utility regulators in a state decide that resilience is an important objective. In this instance, regulators might decide that the utility's proposed grid investments are necessary to achieve the resilience objective even if its grid modernization plan does not monetize the resilience benefits.

According to the DOE Guidebook, grid modernization investments can be broken down into two categories for economic analysis:

- Core components - Least-cost, best-fit approach for projects deemed to be necessary
- Application projects - BCA approach because these projects are optional and do not play as big a role in supporting other grid modernization projects[26]

Another approach is categorizing grid modernization investments by four main investment rationales, or drivers:[27]

1. *Joint benefits:* core platform investments that are needed to enable capabilities and functions;[28]

[22] DOE Guidebook, page 85.
[23] DOE Guidebook, page 83.
[24] DOE Guidebook, page 31.
[25] DOE Guidebook, page 82.
[26] DOE Guidebook, page 86.
[27] DOE Guidebook, page 84.
[28] Investments justified by joint benefits might include, for example, ADMS or DSCADA.

2. *Standards compliance and policy mandates:* utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DER;
3. *Net customer benefits:* utility investments from which some or all customers receive net benefits in the form of bill savings; and
4. *Customer choice:* investments triggered by customer interconnection, opt-in utility programs, and customer-driven reliability improvements paid for by individual customers.

These investment drivers can be used to determine which analytical method should be applied to grid modernization investments—in particular:

- Investments driven by *joint benefits* or *compliance with standards or policy mandates* should be subject to a least-cost, best-fit approach.
- Investments driven by *net customer benefits* should be assessed using a standard BCA approach to demonstrate that the investment will provide net benefits.
- Investments driven by *customer choice* are considered "self-supporting," assumed to be cost-effective from the customer's perspective, and therefore do not need to be assessed by utilities or regulators.[29]

The extent to which the least-cost, best-fit approach or the BCA approach is used will vary across states, depending upon each state's objectives, priorities, and proposed investments. Core components typically account for the majority of grid modernization investments.[30]

Prioritization of grid modernization investments is an important aspect of the economic analysis. Grid modernization plans often propose large capital investments that might be burdensome to put into electricity rates all at once. This challenge is especially problematic if the plan does not provide a quantitative, monetized demonstration that customer benefits will exceed customer costs. According to the DOE Guidebook, "the goal of prioritization is to identify least-regrets investments that balance risk, cost, short-term functionality and value, and long-term functionality and value."[31] It recommends that prioritization be supported with risk-based techniques applied as part of the strategic planning and economic analysis.

The DOE Guidebook also discusses several other important aspects related to the economics of grid modernization investments. These include the roles of *ex ante* and *ex post* economic evaluations, coordinated planning, and clearly defined performance metrics.

California Public Utilities Commission Grid Modernization Proceeding

The California Public Utilities Commission (CPUC) recently issued an order addressing grid modernization planning and analysis, particularly regarding the interrelationship between grid modernization projects and DERs.[32] The order includes several findings and recommendations that might be helpful for other jurisdictions considering the economics of grid modernization investments.

[29] DOE Guidebook, page 84.
[30] DOE Guidebook, page 90.
[31] DOE Guidebook, page 98.
[32] CPUC 2018.

The CPUC notes that many grid modernization investments are intended to support the integration of DERs, as well as to achieve traditional distribution objectives, such as reliability and safety. The Commission found that grid modernization proposals must be considered holistically, accounting for reliability and safety objectives as well as the objective of integrating DERs. According to the CPUC, separate evaluation of the reliability and safety benefits from the benefits associated with DERs "would not be feasible."[33] The CPUC also found that the same threshold of review should be applied to investments made for reliability/safety objectives and for DER objectives.[34] For these reasons, the CPUC found that "the cost-effectiveness of grid modernization needs to be evaluated within the context of the overall cost-effectiveness of the DERs."[35]

The CPUC declined to require utilities to make a cost-effectiveness showing in order to justify grid modernization investments. Instead, utilities must demonstrate the *cost reasonableness* of grid modernization investments, which requires a demonstration that the investments meet distribution planning objectives at the lowest possible cost.[36]

The Commission finds that the "most appropriate approach to evaluate the cost reasonableness depends on what drives an investment: (1) to integrate and maximize the value of DERs, (2) to mitigate forecasted safety and reliability challenges based on either growth of DERs, or growth in demand, or (3) [a] combination of these drivers."[37] For this reason, in their requests for recovery of grid modernization costs, the CPUC requires utilities to explain what drives the need for each type of grid modernization investment.

The CPUC identifies three general approaches that can be used to determine the appropriate level of investment in DER integration:[38]

1. Use existing methods for evaluating cost-effectiveness of distribution investments, including the use of outage and safety metrics, particularly for meeting reliability and safety objectives.
2. Identify the lowest cost approach to meeting grid needs—least-cost, best-fit. This approach might be used for investments driven by either reliability/safety or DER integration.
3. Use the comprehensive, long-term IRP process to evaluate the cost-effectiveness of DERs, taking into account "naturally occurring" DERs as well as the potential for the utility to promote additional DER integration.

The Commission does not specify the extent to which any one of these approaches must be used for specific grid modernization proposals, and in practice they might all be used. For example, the IRP process can be used to determine a cost-effective level of DERs, and that level of DERs can be used to justify investments in grid modernization projects necessary to support them. The least-cost, best-fit approach can be used to demonstrate that the grid modernization projects meet the DER objectives at the lowest cost, and metrics can be established to demonstrate that those objectives are achieved over time.

The CPUC order includes a comprehensive template for grid modernization filing requirements.[39] It also includes a comprehensive classification of grid modernization investments.[40]

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[33] CA PUC 2018, page 6 and page 24.
[34] CA PUC 2018, page 24.
[35] CA PUC 2018, page 24.
[36] CA PUC 2018, page 25.
[37] CA PUC 2018, page 26.
[38] CA PUC 2018, page 26.
[39] CA PUC 2018, Appendix A.
[40] CA PUC 2018, Appendices B and C.

Choice of Discount Rate

The discount rate is an important input to any BCA and has significant impacts on the results. Discount rates are often described as reflecting the cost of capital, the opportunity cost, or the risk associated with the future value of money. In regulatory settings, a discount rate reflects a particular "time preference," which is the relative importance of short- versus long-term costs and benefits.[41] A higher discount rate gives more weight to short-term impacts, while a lower discount rate gives more weight to long-term impacts.

Table 5 presents some example discount rates that could be used for utility grid modernization BCA. Many recent grid modernization plans and state BCA frameworks use the utility Weighted-Average Cost of Capital (WACC) as the discount rate.

Table 5. Example Discount Rates for Utility BCA

Note: Illustrative values are in real terms—i.e., net of inflation adjustments.

Type of Discount Rate	Illustrative Values
Investor-owned utility weighted average cost of capital	5%–8%
Publicly owned utility weighted average cost of capital	3%–5%
Utility customers	Varies widely
Low risk	0%–3%
Societal	<0%–3%

One of the challenges in choosing a discount rate for grid modernization BCA is that grid modernization sometimes includes projects driven by state energy goals and societal benefits. Consequently, the utility WACC might not be the appropriate discount rate to use. The utility WACC reflects the opportunity costs (i.e., time preference) of utility investors, but does not necessarily reflect a time preference consistent with regulatory goals. A discount rate based on the utility WACC is typically higher than one that reflects regulatory goals, which is closer to a low-risk or a societal discount rate.

The choice of discount rate has no bearing on whether the utility can recover its actual cost of capital. In any BCA, the cost of capital should be included in the undiscounted annual revenue requirement forecasts for each investment, and the utility should be allowed to recover any such prudently incurred costs. The choice of discount rate simply affects how much weight to give long-term impacts relative to short-term impacts, to help public utility commissions make decisions about whether the investment is consistent with regulatory goals.

Benefit-Cost Analysis Versus a Business Case Approach

Some grid modernization plans use a "business case" approach to evaluating investments, instead of a BCA approach.

- The term *benefit-cost analysis* is generally used to refer to an analytical approach that puts all costs and benefits into monetary values. The monetary values are often presented in terms of an annual stream of costs and benefits over the life of the investment, then discounted to determine

[41] NSPM 2017, Chapter 9.

the cumulative present value of costs and benefits. If benefits exceed costs, the investment is typically deemed to be cost-effective.

- The term *business case* is generally used to refer to an approach that is broader and more flexible than a BCA. In general, a business case differs from a BCA in that it accounts for impacts (costs and benefits, but typically benefits) that are difficult to define, isolate, quantify, or monetize. Some business case approaches include a traditional BCA, where many costs and benefits are put into monetary values, but then allow flexibility for deciding whether to pursue an investment after considering factors that have not been monetized. Other business case approaches include little monetization of costs and benefits, relying almost entirely on qualitative, non-monetary grounds for justifying the investment.

This distinction is more rhetorical than substantive. A BCA can account for non-monetary as well as monetary impacts, and a business case can serve the same fundamental objective as a BCA. Regardless of what the approach is called, costs and benefits should be monetized to the fullest extent possible, and unmonetized costs and benefits should be accounted for as much as is feasible.

4.0 Trends in Recent Grid Modernization Plans

General Trends

We reviewed 21 grid modernization plans prepared by electric utilities across the United States (Table 6). Five of these plans were submitted in the context of rate cases, while the others were filed for review and approval in a separate docket. Almost all these plans were submitted for public utility commission review prior to making the proposed grid modernization investments.

Table 6. Grid Modernization Plans Reviewed[42]

Utility	State	Year	Utility	State	Year
National Grid	NY	2016	DTE Energy	MI	2018
NYSEG & RGE	NY	2016	APS	AZ	2016
Unitil	MA	2015	PSE&G	NJ	2018
National Grid	MA	2016	LGE	KY	2018
Eversource	MA	2015	Consumers Energy	MT	2018
Public Service Company	CO	2016	Central Hudson Gas & Electric	NY	2018
SDGE	CA	2016	Hawaiian Electric Companies	HI	2017
Xcel	MN	2017	Southern California Edison	CA	2016
FirstEnergy	OH	2017	Connecticut Light and Power	CT	2010
Vectren	IN	2017	Entergy	AR	2016
National Grid	RI	2018			

We found wide variety in the assumptions, methodologies, justifications, and documentation across these plans. Many of the plans did not include all information or analysis needed for a thorough regulatory review of the grid modernization projects. Some of the key items that were lacking in the plans include:

- An overarching rationale for grid modernization investments and an explanation of how individual components will help meet overall goals.

- Identification of which cost-effectiveness test was used for the BCA. Based on our assessment of the cost and benefits included in the 15 plans in our review that included monetary costs or benefits, it appears as though nine used a Utility Cost test, three used a Societal Cost test, two used both types of tests, and one used a TRC test.

- Identification of which discount rate was used to determine present values. Based on our assessment of the discount rates used, roughly half of the plans used the utility WACC as the discount rate; the remaining plans did not specify the discount rate used.

- Methodologies to account for the interdependencies of grid modernization components. Some of the plans use the rationale that grid modernization investments are foundational, platform investments, and therefore do not need to have benefits monetized or assigned to each grid modernization component.

42 DTE Energy and Consumers Energy filed plans in 2017 that were superseded in 2018.

- Methodologies to account for unmonetized benefits of grid modernization components because of the interdependencies of grid modernization components and the difficulty of monetizing some of the benefits.

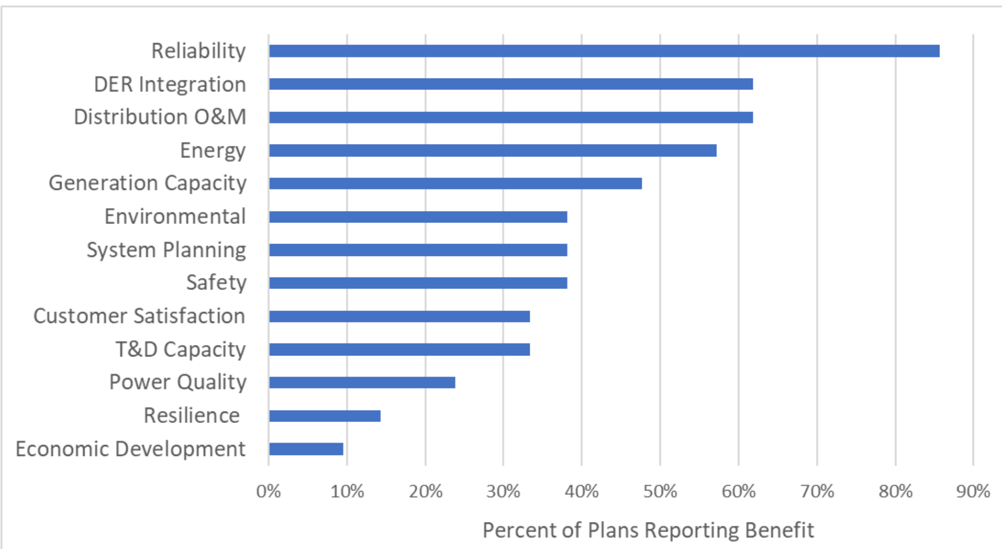
- Robust definitions of grid modernization metrics and how they will be used to monitor grid modernization costs and benefits over time.

- Methodologies or discussions of how to address customer equity issues.

Types of Benefits Claimed

Figure 4 shows the frequency with which utilities claimed certain benefits from grid modernization plans (including both monetized and unmonetized benefits). Nearly all plans claim reliability as a benefit; the majority of plans claim O&M, energy savings, and DER integration as benefits; and many plans include generation capacity. Few plans claim power quality, resilience, or economic development benefits.

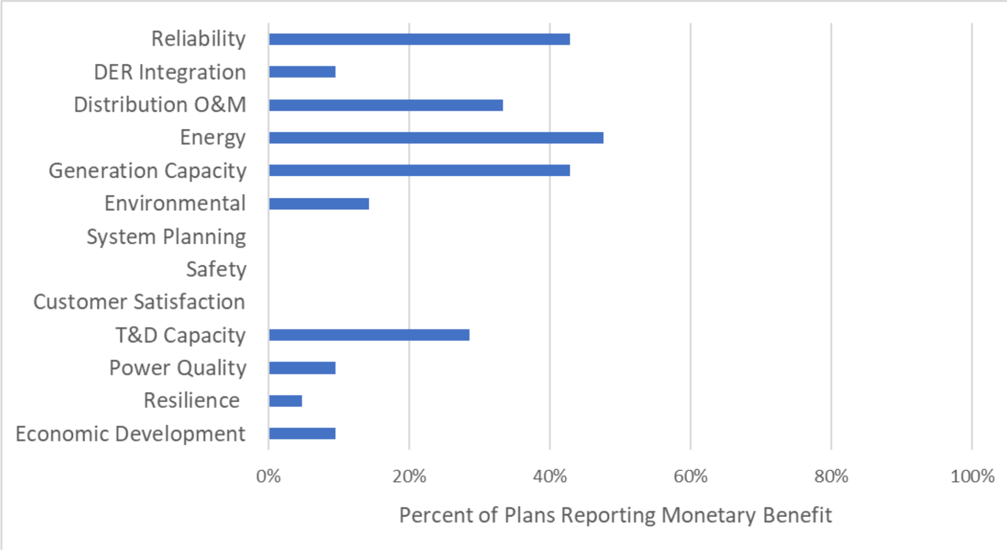
Figure 4. Type and Frequency of Benefits Claimed in Grid Modernization Plans



Use of Monetized Benefits

Figure 5 shows the frequency with which utilities present monetized benefits in their grid modernization plans. Most of the monetized benefits are claimed for energy, generation capacity, and O&M savings, as well as reliability benefits.

Figure 5. Type and Frequency of Monetized Benefits Claimed in Grid Modernization Plans



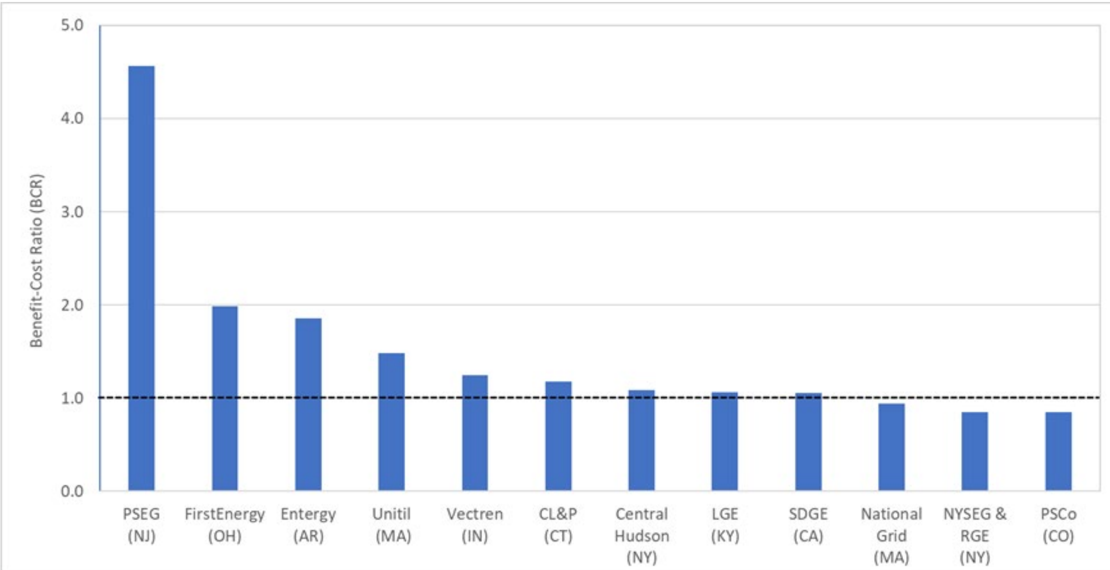
Examples of Monetized BCA Results

Figure 6 presents high-level results from the subset of grid modernization plans that include monetary values for costs and benefits. The figure presents benefit-cost ratios for the entire portfolio of grid modernization components. We present benefit-cost ratios because they are easy to compare across a range of utilities and grid modernization plans, and they are a conventional way to present bottom-line results from BCA.

Few of the grid modernization studies presented results in terms of a benefit-cost ratio. This situation may be because these ratios can mask some of the important challenges and considerations that affect the ultimate decision of whether benefits exceed costs for a grid modernization project. Notably, many of the benefit-cost ratios presented in Figure 6 are from studies that do not include monetary values for some of the benefits. Thus, these ratios only tell part of the story and could be misleading if not considered properly.[43] Nonetheless, we present the ratios here because they illustrate the extent to which unmonetized benefits will be needed to demonstrate that the portfolio benefits exceed the costs.

[43] While the plans that were reviewed commonly left some claimed benefits unmonetized, Figure 7 does not include cases in which monetization was demonstrably incomplete. National Grid NY, for example, monetized benefits for just the VVO/CVR components of its plan, representing only about $42 million out of a total proposed investment of $585 million. The utility's plan is therefore not included.

Figure 6. Grid Modernization Benefit-Cost Ratios[44]



[44] Benefit-cost ratios were calculated from present value benefit and cost figures. We followed the cost-classifying conventions of individual reports, including all costs and benefits that were indicated to be associated with the grid modernization initiative. In some cases (e.g., PSCo), our figures include advanced metering infrastructure (AMI), while we omit AMI in others (e.g., PSE&G). If the utility provided both shorter- and longer-term values, we used longer-term values. The National Grid Massachusetts plan included several scenarios. We present here the Balanced scenario.

5.0 Options for Addressing Key BCA Challenges for Grid Modernization

This section provides options for addressing some of the more challenging aspects of BCA for grid modernization. Table 7 lists the key challenges and summarizes the discussion of potential approaches that follows.

Table 7. Options for Addressing Key BCA Challenges

Challenge	Potential Approaches
Identifying objectives	• Use long-term strategic planning to define objectives upfront • Identify the amount and type of cost-effective DERs
Documenting the purpose of each grid modernization component	• Specify a standard taxonomy for grid modernization • Define purpose and driver of each grid modernization component
Determining when to apply least-cost, best-fit approach	• Consider grid modernization objectives • Consider purpose and driver of the component • Consider whether component is core or application
Choosing BCA framework	• Articulate the BCA framework upfront • Focus on two tests: Utility Cost test and Regulatory test
Choosing discount rate(s)	• Choose a discount rate that reflects state regulatory goals • Conduct sensitivities using different discount rates
Accounting for interactive effects	• Use the least-cost, best-fit approach where warranted • Use scenario analysis with different combinations of components • Conduct BCA for grid modernization components in isolation
Accounting for benefits that are hard to quantify or monetize	• Use the least-cost, best-fit approach where warranted • Establish metrics to assess the extent of benefits • Apply methodologies to make unmonetized benefits transparent
Addressing uncertainty	• Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling
Putting BCA results in context	• Estimate long-term bill impacts
Prioritizing grid modernization investments	• Identify least-regrets investments that balance cost, risk, functionality and value
Encouraging follow-through	• Establish metrics to monitor achievement of benefits

Identify Objectives

Defining grid modernization objectives is critical to help guide utility decision-making and justify certain grid modernization investments. Ideally, these objectives would be identified, reviewed, and approved by the public utility commission prior to the development of a grid modernization plan.

Further, it would be best to develop these objectives through a long-term, strategic grid modernization planning process. Such a process would incorporate distribution, transmission, and generation resource planning as much as possible to identify the role of grid modernization investments in the context of the entire utility system.

Such a process also should analyze opportunities for implementing cost-effective DERs to meet future electricity needs. Given that many grid modernization investments are intended to support the implementation of DERs, it is important to assess the type and level of benefits DERs are likely to provide.

Documenting the Purpose of Each Proposed Grid Modernization Investment

Regulatory review of grid modernization plans will be greatly facilitated if utilities fully document the purpose of each grid modernization component, as well as the purpose of the total portfolio of these components. Section 2 of this report describes DOE's taxonomy for identifying principles, objectives, capabilities, functionalities, and technologies for grid modernization proposals. This taxonomy could be used to provide a justification for how certain components and technologies will meet regulatory objectives and comply with regulatory principles. This taxonomy also can be used to assist with decisions regarding the timing and the proportional deployment of grid modernization components.

In their grid modernization plans, utilities should distinguish between proposed investments that are core components and applications. Further, they should explain how each proposed investment in the context of stated objectives, whether proposed investments are needed to meet regulatory standards and requirements, and whether they are needed to enable other technologies or resources.

Articulating the purpose of each proposed grid modernization investment in these ways will aid state regulators in determining when to apply a least-cost, best-fit approach or a BCA approach.

Determining When to Apply the Least-Cost, Best-Fit Approach

The least-cost, best-fit approach may be warranted when there is a clearly defined need for a grid modernization investment and the purpose of the analysis is how to best meet regulatory requirements and objectives.

Compared to the BCA approach, this approach offers several advantages: It is relatively simple, accounts for interactive effects of grid modernization components, and does not require detailed, monetary estimates of benefits because they already have been deemed to be sufficient. However, the least-cost, best-fit approach does not quantify the net benefits to customers of meeting identified objectives. Consequently, regulators may wish to apply the least-cost, best-fit approach judiciously to those grid modernization components that are necessary to meet regulatory requirements and objectives.

As described above in Section 3.0, regulators can take into account several considerations to determine whether to apply least-cost, best-fit to proposed grid modernization investments. First is whether the proposed investment is a core component or an application. *Core*, or platform, components represent foundational elements that are necessary for providing the services required of modern grids. These components are therefore well-suited for the least-cost, best-fit approach. *Applications*, or modules, represent additional, single-purpose components that can be layered on top of the core components to provide additional functionality. Such components are therefore well-suited for the BCA approach.

Another consideration is the driver, or rationale, for the proposed grid modernization investment. The DOE Guidebook recommends that investments driven by *joint benefits* or *compliance with standards* or *policy mandates* should be subject to a least-cost, best-fit approach, whereas investments driven by *net customer benefits* should be assessed using a standard BCA approach to demonstrate that the investment will provide net benefits.

The utility's justification for using a least-cost, best-fit approach to economic evaluation of proposed grid investments should include a complete description of whether and how each proposed grid modernization component:

- is needed to meet objectives identified in a utility's long-term, strategic grid modernization plan;
- should be defined as a core component;
- is driven by compliance with standards or regulatory mandates; and
- is driven by the need to provide joint benefits or enable interrelated components.

Public utility commissions will review these justifications and consider the costs. For example, while the commission might agree to increased reliability as an objective, various grid modernization components might offer different degrees of increased reliability, at different costs to customers. As another example, a variety of options may be available for meeting regulatory mandates, and public utility commissions can compare those options using a BCA approach.

In some cases, a combination of least-cost, best-fit and BCA approaches may be appropriate. For example, if a utility proposes grid modernization components for the purpose of supporting increased integration of DERs, the utility should ideally conduct long-term strategic planning exercises to determine the objectives of grid modernization and assess the cost-effectiveness of DERs. If the utility finds the DERs to be cost-effective, the objective may to make grid modernization investments to enable their deployment. This objective then justifies the application of the least-cost, best-fit approach for assessing those grid modernization investments.

Choosing a Benefit-Cost Analysis Framework

Ideally, public utility commissions should articulate a BCA framework for grid modernization prior to the development and submission of grid modernization plans. This allows for stakeholder input and regulatory guidance in developing the framework, outside of the review of specific grid modernization proposals. Such a framework also allows the utility to conduct a more robust BCA for specific proposals so that commissions and stakeholders can focus on the analyses and results rather than the framework itself.

Public utility commissions may wish to require the use of multiple tests for grid modernization BCA, because a single test is unlikely to provide all the relevant information for deciding what projects are likely to provide net benefits and be consistent with regulatory goals.

The Utility Cost test provides extremely useful information for determining the likely costs and benefits for all electricity customers. This test provides an indication of how utility revenue requirements and average customer bills will be affected by grid modernization proposals. It is a conventional test that has been used for many years to assess whether utility investments are reasonable and in the public interest.

One limitation of the Utility Cost test is that it does not account for some regulatory goals, some of which are instrumental drivers behind grid modernization proposals. For example, the traditional Utility Cost test does not account for low-income customer benefits, but this may be an important regulatory goal. The typical response to this limitation of the Utility Cost test is to use the Societal Cost test because it better accounts for regulatory goals.[45]

[45] DOE 2017, Volume III; EPRI 2015; NY PSC 2016; RI PUC 2017.

As Section 3 explains, the National Standard Practice Manual articulates a more nuanced approach to determining a BCA test. Utilities and public utility commissions do not need to be confined to the traditional Utility Cost or Societal Cost tests. Instead, they can develop a Regulatory test that reflects the regulatory perspective and accounts for specific regulatory goals of their state. Such a test would likely be broader than the Utility Cost test and narrower than the Societal Cost test.

To gain a thorough understanding of the benefits and costs of grid modernization, it might be best to apply both the Utility Cost test and the Regulatory test. The former provides a relatively simple indication of costs and benefits to utility customers that are paying for grid modernization, and the latter indicates how grid modernization projects are likely to meet regulatory goals and objectives more broadly.

All the BCA tests are limited in that they do not provide much useful information on customer equity issues. They do not indicate whether some customers will experience very different costs or benefits than others, or whether some customers will experience enhanced electricity services more than others. Below we discuss options for state public utility commissions to address customer equity concerns.

Choosing a Discount Rate

In the context of utilities under the oversight of a state public utility commission, the choice of discount rate is essentially a regulatory decision. It does not influence the utility's cost of capital, nor does it influence the utility's ability to recover its cost of capital. The discount rate chosen for grid modernization BCA, or any BCA, should reflect the regulatory time preference—i.e., the priority that the public utility commission wishes to place on short-term versus long-term impacts of grid modernization.[46] This regulatory time preference should reflect the energy goals of the state and be informed by robust stakeholder discussion and input.

Further, the choice of a discount rate should recognize the objective of the BCA. In this case, the objective of the BCA is to determine whether proposed grid modernization investments will help meet the overall goals of safe, reliable, low-cost, equitable service to customers over the selected timeframe.

As noted above, many grid modernization plans use the utility WACC as the discount rate. The utility WACC reflects the time preference (i.e., the opportunity costs) of utility investors, but might not reflect a time preference that is consistent with regulatory goals. Consequently, the utility WACC might not be the appropriate discount rate to use for grid modernization BCA. A discount rate based on the utility WACC is typically higher than one that reflects regulatory goals.[47]

Estimates of utility costs for BCA analysis should use the cost of capital incurred by the utility for each investment, because this reflects actual costs incurred. The choice of discount rate, however, does not have to equal the utility's cost of capital. The utility's cost of capital is used to develop the best forecast available of likely costs incurred over the study period, while the discount rate is used to determine how much weight to give to short-term versus long-term costs when making decisions about utility investments.

The utility WACC offers the advantage of being a conventional approach familiar to utilities and public utility commissions. However, a discount rate that reflects regulatory goals has the advantage of being

[46] NSPM 2017, Chapter 9. This issue of short-term versus long-term priorities is separate from the decision about the length of the study period of the economic analysis. The length of the study period should always be sufficient to capture the anticipated lifetime costs and benefits of the proposed investments. The discount rate decision affects how much weight to give to the short-term versus long-term impacts throughout the study period.

[47] NSPM 2017, Chapter 9.

consistent with the objective of the BCA and better reflecting regulatory priorities. Public utility commissions could require utilities to analyze grid modernization scenarios with both the conventional utility WACC discount rate and a different discount rate that reflects regulatory goals. For example, a reference case could use the utility WACC, and a sensitivity case could use a lower discount rate to reflect the regulatory time preference.

Accounting for Interdependent Components

One of the most vexing challenges of grid modernization BCA is to properly understand and account for the interdependencies among different grid modernization components. The interdependence among some components raises the question of whether they should be reviewed in isolation, in combination with others, or as part of a single portfolio. None of the 21 grid modernization plans we reviewed evaluated every component in isolation. Most plans bundled components in logical configurations, and some plans simply reviewed all grid modernization components as a single portfolio.

Each public utility commission will need to answer this separation-versus-bundling question in a way that suits its needs, depending on the level of scrutiny it chooses to apply in reviewing grid modernization proposals.

One way to address interdependent components is to apply the least-cost, best-fit approach to grid modernization projects that are especially interdependent or fundamental. As described in Section 2, this approach can be used for platform components that play a foundational role in the grid modernization projects and are often needed to enable or support other grid modernization projects. If the least-cost, best-fit approach is used for some grid modernization components, then these components can be evaluated as a portfolio, and it is not necessary to evaluate each of them in isolation.

If public utility commissions are not satisfied with the justification for the least-cost, best-fit approach, or if they seek more information than is provided by that approach, they can direct the utility to conduct economic analyses to illustrate the implications of combining grid modernization components into logical bundles based on their interdependent natures and how they might support policy and timing objectives. Analyzing grid modernization components in logical bundles can provide useful information on their costs and benefits without conducting a BCA for each component in isolation.

A bundling analysis might include different combinations of grid modernization components that are considered foundational, or different combinations of foundational and optional grid modernization components. The example below illustrates how a bundling approach can be used to investigate interactive effects.

Example: Bundling Scenarios Can Be Used to Evaluate Interdependencies

In this example a utility is proposing the following components as part of its grid modernization plan: ADMS, GIS, DSCADA, OMS, FLISR, DERMS, AMI, and VVO. The utility conducts several scenarios to demonstrate the costs and benefits of different combinations of technologies. The first scenario includes all the components that are considered to be platform components: ADMS, GIS, DSCADA, and OMS. The second scenario adds two modular applications to the platform components: FLISR and VVO. The third scenario adds two more modular applications (AMI[48] and DERMs) to the second scenario.[49] Table 8 presents hypothetical results of these three scenarios.

Table 8. Example of Scenarios to Test Interactive Effects

	1. Platform Components Only	2. Platform Plus FLISR and VVO	3. Scenario 2 Plus AMI and DERMs
Costs (Mil PV$)	24	28	32
Benefits (Mil PV$)	22	36	38
Net Benefits (Mil PV$)	-2	8	6
Benefit-Cost Ratio	0.9	1.3	1.2
Findings:	not cost-effective	cost-effective	potentially cost-effective

In this hypothetical example:

- Scenario 1 is not cost-effective. Regulators should be reluctant to approve such a scenario that includes platform components only.
- Scenario 2 is cost-effective. This finding suggests that the platform components are a reasonable investment, as long as they are used to support cost-effective modular applications.
- Scenario 3 could be interpreted in two ways. One interpretation is to decide that AMI and DERMs are reasonable investments because they will result in net benefits to customers when combined with other grid modernization components. Another interpretation is that AMI and DERMs are not cost-effective because they reduce the net benefits offered by the other grid modernization components in Scenario 2. The choice of interpretation is up to each state.

The results for Scenario 3 suggest additional analysis may be warranted. One option is to prepare additional scenarios with AMI separated from DERMs to see how cost-effective they are on their own. Another option is to look deeper into the unmonetized benefits of this scenario. This option is addressed in the example presented in the following section.

Accounting for Unmonetized Benefits

Grid modernization benefits should not be ignored because they are not monetized. Assuming that these benefits do not exist or are not worth anything skews BCA against grid modernization projects. Conversely, providing only qualitative justification for benefits does not provide public utility commissions and others with sufficient evidence to determine if benefits exceed the costs.

[48] This analysis might focus on just the smart meter component of AMI.
[49] A variety of other scenarios could be evaluated to test components in isolation or in other combinations.

Several approaches can be used to improve how grid modernization BCA accounts for unmonetized benefits:

1. *Put as many benefits as possible in monetary terms.* Methodologies are improving for monetizing some benefits that have been hard to monetize in the past—for example, for resilience.[50] Utilities can use the most up-to-date practices to monetize benefits wherever possible. Any monetization of hard-to-monetize benefits should be fully documented and justified.

2. *Define benefits in such a way that they can be monetized.* For example, in the 21 grid modernization plans we reviewed, many utilities cited increased DER adoption as a key benefit, but none of them provided a monetary value. If this benefit were instead defined in terms of the reduced generation, transmission, and distribution costs associated with the incremental DERs, the benefit could be monetized. If these benefits are already included in the monetized energy, capital, and O&M savings, then perhaps increased DER adoption should not be included among the benefits, to avoid double-counting and to reduce the number of benefits expressed only in qualitative terms.

3. *Provide as much quantitative data as possible*. Quantitative data can be useful, even if it is not put into monetary terms. For example, providing estimates of the type and magnitude (numbers, capacity, energy) of incremental DERs implemented as a result of grid modernization can be useful for assessing the value of that benefit.

4. *Use the least-cost, best-fit approach to mitigate the need to develop monetary estimates for all benefits.* This approach is focused entirely on costs, seeking to find the lowest-cost way to achieve the best fit and desired outcomes. However, the least-cost, best-fit approach should be applied only to those grid modernization components that are deemed to be necessary.

5. *Establish metrics to assess benefits, especially those that are not monetized.* Metrics are important to assess progress toward achieving benefits.[51] For example, if the utility does not monetize safety, resilience, or power quality benefits in its grid modernization plan, state regulators can establish metrics to indicate the extent to which these benefits will be experienced. Metrics can offer a quantitative way to assess the extent of the benefit, short of having monetary values for this purpose.

6. *Apply quantitative techniques that can provide helpful information regarding the impacts of unmonetized benefits on BCA results.* This quantification could include, for example, using a point system to assign value to unmonetized benefits; using a weighting system to assign priorities to unmonetized benefits; assigning proxy values for significant unmonetized benefits; and using multi-attribute decision-making techniques. The example below illustrates how a point system can be used to consider unmonetized effects.

[50] Converge 2019.
[51] GMLC 2017.

Example: A Point System Can Be Used to Consider Unmonetized Benefits

This example builds off the previous example. A utility is proposing the following components as part of its grid modernization plan: ADMS, GIS, DSCADA, OMS, FLISR, DERMS, AMI, and VVO. The utility conducts three scenarios, equivalent to the previous example: (a) including all the components that are considered to be platform components, (b) adding two modular applications to the platform components, and (c) adding two more modular applications to the second scenario.

Also, in this example, the utility has identified two benefits that are expected to be significant but were not monetized: increased resilience and increased customer choice and flexibility. The utility assigns points for these benefits to each of the scenarios: 0 = no benefits; 1 = low benefits; 2 = moderate benefits; and 3 = high benefits. Table 9 presents some hypothetical results using this approach.

Table 9. Example of Scenarios to Account for Unmonetized Benefits

	1. Platform Components Only	2. Platform Plus FLISR and VVO	3. Scenario 2 Plus AMI and DERMS
Monetary Impacts:	---	---	---
Costs (Mil PV$)	24	28	32
Benefits (Mil PV$)	22	36	38
Net Benefits (Mil PV$)	-2	8	6
Benefit-Cost Ratio	0.9	1.3	1.2
Unmonetized Impacts:	---	---	---
Resilience	1	1	3
Customer Choice & Flexibility	1	2	3
Findings:	not cost-effective	cost-effective	cost-effective

In this hypothetical example:

- Scenario 1 is not cost-effective based on monetary impacts, and the additional unmonetized points are not very high. This suggests that Scenario 1 might not be cost-effective.

- Scenario 2 is cost-effective based on monetary impacts alone and is even more cost-effective considering the additional unmonetized points.

- Scenario 3 is not most cost-effective based on monetary impacts alone, because it reduces the net benefits and the benefit-cost ratio relative to Scenario 2. However, this scenario is assumed to have significant resilience and customer choice and flexibility benefits, as indicated by the unmonetized points. Given this additional information, regulators might decide that this scenario is cost-effective.

Accounting for Uncertainty

All utility planning exercises involve a significant amount of uncertainty, and grid modernization BCAs are no exception. Grid modernization projects involve many uncertainties related to implementation costs, operating costs, technology performance, customer adoption of DERs, technological obsolescence, stranded assets, and evolution of new customer options such as community choice aggregation and third-party service providers.

Grid modernization BCA should take advantage of a variety of approaches that are currently used to account for uncertainty in long-term utility resource planning exercises.[52] Uncertainty considerations can be applied at the technology level. For example, proxy values can be applied to represent positive or negative risk by applying contingency costs or by using ranges of costs or benefits. Uncertainty considerations can be accounted for more broadly across the utility system using techniques such as probabilistic modeling or expected value assessments.[53] Systemic industry uncertainties, such as evolution of new customer options, can be accounted for using scenario and sensitivity analyses.

Bill Impact Analyses

BCA results are typically presented in terms of net present values of costs and benefits. But without more context, it is difficult to assess how these costs and benefits will directly affect customers and the costs they pay for electricity services.

Long-term bill impact analyses can complement BCA by providing information on how much typical customer bills are likely to increase or decrease as a result of the proposed grid modernization projects. While customer bills are not the only measure of net benefits, customer service, or customer satisfaction, they are an important metric nonetheless. Bill impact analyses are frequently performed in the context of rate cases, and the same technique can be applied to grid modernization BCA.

Bill impact analyses should use a study period that is as long as the BCA study period. While the costs of grid modernization projects tend to occur in the early years, benefits are experienced over the long term. Bill impact analyses should use the same costs and benefits that are included in the Utility Cost test because this test includes the revenue requirement impacts that affect customer rates and bills.

Generally, bill impact analyses should be based on the entire portfolio of grid modernization components, rather than separate components. However, if public utility commissions want to investigate certain marginal grid modernization components, it might be useful to conduct bill impact analyses on those components in isolation.

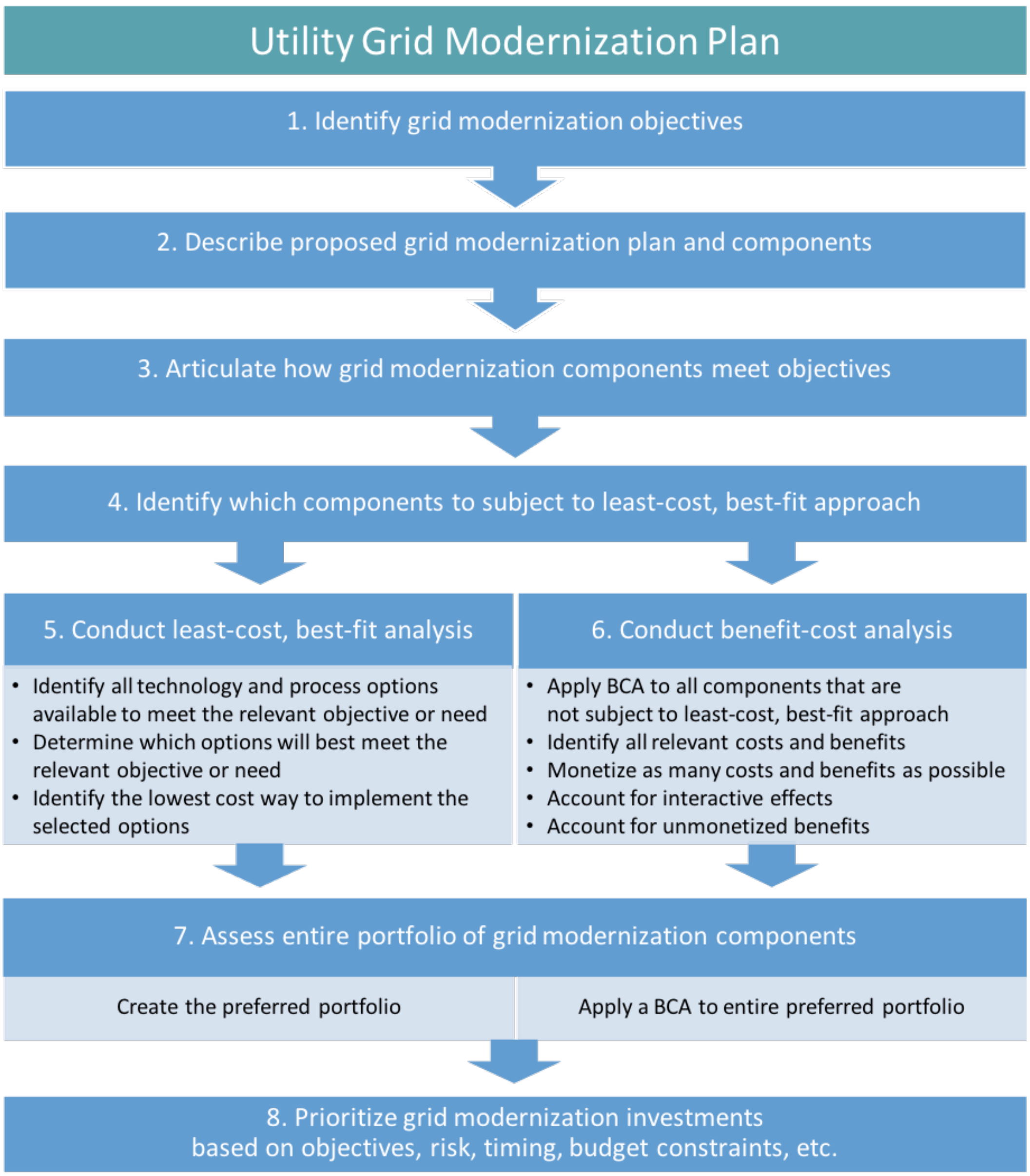
[52] See CERES 2012, especially chapter 4.
[53] For more information on risk assessment and management, see IEC 2019.

6.0 Summary

This section provides a summary of the process for developing BCA for grid modernization investments.

Figure 7 presents a chart showing steps a utility can take to develop a grid modernization BCA, based on the approaches described in this report and consistent with DOE's Guidebook. The chart depicts an aspirational or ideal process from the perspective of regulatory review. It provides as much transparency as possible for the benefit of public utility commissions, utility consumer representatives, and other stakeholders reviewing the BCA.

Figure 7. Steps for Conducting a Grid Modernization BCA



Following is a description of each of the steps in Figure 7.

1. **Identify grid modernization objectives**. Use a long-term strategic grid modernization plan to identify objectives, including reliability and safety objectives, regulatory mandates, and regulatory policy goals.

2. **Describe the proposed grid modernization plan and components**. This step includes a thorough description of each of the grid modernization components independently as well as how they interact with each other, and whether and how the components enable other components.

3. **Articulate how the grid modernization projects meet objectives**. Grid modernization investments are often justified on the basis of a variety of benefits that are beyond the minimum regulatory requirements of providing safe and reliable service at reasonable cost. If a utility seeks to justify grid modernization investments based on other regulatory objectives, these goals should be clearly articulated in the grid modernization proposal.

4. **Identify which components should be subject to a least-cost, best-fit approach**. Proper documentation for when to apply the least-cost, best-fit approach is critical to ensuring that the economic analysis provides sufficient justification of benefits to customers. There are several factors to consider when making this determination, including whether the component is a core component, whether the component is necessary to meet stated objectives, whether the component is needed to meet regulatory standards and requirements, whether the component is needed to enable other technologies or resources, and how much scrutiny the public utility commission wants to apply to specific components.

5. **Conduct the least-cost, best-fit analysis**. This step requires identifying all of the technology and process options available to meet the relevant objective or need, determining which options will best meet those objectives and needs, and identifying the lowest cost way to implement the selected options. These tasks can be supported by issuing requests for proposals for qualified vendors to meet the objectives and needs at the lowest cost.

6. **Conduct the BCA**. A standard BCA approach should be applied for all grid modernization components that are not subject to a least-cost, best-fit approach, or that public utility commissions decide warrant greater scrutiny than offered by that approach. Using a standard BCA approach, the utility makes a clear case that the benefits exceed the costs for each proposed investment.

    Identify all relevant costs and benefits. Begin with a full inventory of all relevant costs and benefits for each component under consideration. This inventory should be consistent with the primary and secondary BCA tests identified by the public utility commission.

    Monetize as many costs and benefits as possible. Monetizing as many of the costs and benefits as possible makes the BCA more transparent and reduces the need to account for unmonetized impacts using alternative approaches.

    Conduct a BCA for the component. This step should account for all monetary costs and benefits for each component in isolation.

    Account for interactive effects. One way to account for interactive effects of grid modernization components is to combine them in logical bundles to assess how they provide benefits when operating together (see Section 5).

Account for unmonetized benefits. In the absence of monetary values for some benefits, other quantitative techniques can provide helpful information regarding likely impacts of a grid modernization component (see Section 5). Such techniques could be applied at this stage for components expected to have significant benefits that are not monetized and a benefit-cost ratio less than 1.0.

7. **Assess entire portfolio of grid modernization components**. This step includes combining the results of the steps above to create a holistic picture of all the grid modernization components that the utility is proposing.

   Create the preferred portfolio. This step uses the combined results of the BCA and the least-cost, best-fit analyses to determine the combination of grid modernization components that best meets regulatory objectives and optimizes net benefits for utility customers.[54]

   Apply a BCA to the entire portfolio. This step includes analyzing all monetary costs and benefits of the preferred portfolio. This analysis serves as a double-check to the least-cost, best-fit analyses. If the preferred portfolio has a benefit-cost ratio exceeding 1.0, then public utility commissions can conclude that the portfolio will result in net benefits to customers. Otherwise, utilities may need to prioritize which investments to make and when.

8. **Prioritize grid modernization investments and objectives**. Utilities can prioritize grid modernization investments based on grid modernization objectives. Prioritization might lead to a longer implementation period with staggered investments, different sequencing of investments, downsizing of investments, or some other way to comply with regulatory constraints. In addition, public utility commissions might cap the level of grid modernization costs that go into retail rates at any one time.

[54] We refer to this portfolio as the "preferred portfolio."

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http://gridmodernization.labworks.org/

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210015-EI

In re: Petition for rate increase by Florida Power and Light Company.
_____________________________/

DEPOSITION OF: MICHAEL SPOOR

AT THE INSTANCE OF: VOTE SOLAR AND CLEO INSTITUTE

DATE: June 16, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:25 p.m.

PLACE: GoToMeeting

REPORTED BY: ANDREA KOMARIDIS WRAY
Court Reporter and
Notary Public in and for the
State of Florida at Large

PREMIER REPORTING
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TALLAHASSEE, FLORIDA
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and we have come to expect to provide to them, we sometimes hear from those customers.

And so, that's why, I can tell you, personally, we're -- I know that it's super important to customers, not only in day-to-day reliability, but also in extreme weather events. And so, to me, I think that certainly highlights, you know, the importance of this.

And the good news, again, as I -- as I highlighted earlier and in my testimony is, because of these levels of excellent reliability we've been providing customers, the number of complaints in reliability have gone down over 32 percent over the last four years.

Q Mr. Spoor, would you mind just giving me a yes-or-no answer to the previous question? I know you -- you've kind of launched into a description, but I don't think that I caught the yes or no at beginning of that answer.

A Yeah. I'm sorry. Can -- can you ask the question one more time?

Q Yes. So, in developing your testimony, are you aware of any conversations that took place with customers describing the actual expenditures you're proposing and the actual benefits you're proposing?

A No, I'm not aware of that.

Q Okay. Thank you.

How much improvement does the company expect in day-to-day non-storm reliability from the 5.64 billion in base capital?

A Yeah, so, the -- the investment that we are proposing to -- to make, it -- it's really kind of two prongs: One is, it's a level of investment that we feel is necessary to maintain a level of reliability that we're already providing customers, which, as I've highlighted a couple of times, is -- is the best in the state and -- much, much better -- 58 percent better on FPL's from the benchmark of 2019, and over 40 percent better for Gulf.

And we have a large infrastructure that we support. It's over 77,000 miles of distribution conductors and over 9,000 miles of transmission. And so, it's not only to maintain that, but also to improve it. And so, we, you know, have a culture of continuous improvement.

And these level of investments, again, will not only maintain the high levels of reliability we're already providing through this large infrastructure that we support, but also, continuous improvement as we move forward with -- with these investments.

Q Mr. Spoor, do you have access to the exhibits

Q Okay. Do you know how that calculation would be performed?

A Can you ask that question again? In terms of -- I'm not sure I follow the question.

Q If you refer back to Interrogatory No. 84, FPL's response --

A Yeah, I have that.

Q Okay. So, you stated, "These initiatives have the potential to deliver approximately 2-to-4-percent annual improvement in SAIDI." Do you see that?

A I do.

Q Do you know how you would calculate -- the 2-to-4-percent improvement -- how that translates into minutes per customer?

A Well, I know that -- and I think this number references, again, at the system level. So, when you say customers, I -- I -- I would -- I would interpret this, as I've stated it, to say at the system level for all customers combined. So, that would be an approximate 2-to-4-percent annual improvement at the system level for all customers.

The other piece, as I highlighted before, is just -- it's not only that continuous improvement, but it's also to maintain the high level of reliability that they're already receiving.

BY MS. OTTENWELLER:

Q I want to turn to your testimony on grid modernization, and I want to refer you to FPL's response to CLEO/Vote Solar Interrogatory No. 86.

A Okay.

Q In Subpart A, we requested a cost-benefit analysis of the company's grid modernization expenditures, correct?

A Correct.

Q And we've established that these expenditures are for day-to-day non-storm reliability improvement, right?

A That is the primary driver, although -- and I reference this in my testimony -- although the primary driver for the smart-grid investments are for day-to-day reliability, we also see benefit from these investments for extreme weather events like tropical storms and hurricanes.

Q Okay. And the first part of FPL's response -- first I should ask: Were you involved in the preparation of this response?

A I was.

Q Okay. In the first part of your response, you refer to a website where the annual reliability reports are filed; is that right?

A Correct.

Q And can you tell me specifically where the company's cost-benefit analyses are located on this website?

A So, I don't have a copy of the annual report in front of me, but that report that we do file provides several of the things that we've been -- we've been talking about here, which is cost of all of our initiatives and -- reliability initiatives, I should say -- and smart-grid investment and -- as well as the -- the results, again, that we've been talking about, the SAIDI and the SAIFI and the best-in-state reliability that we provide to customers.

Q Does it also include a benefit/cost analysis that the company conducted?

A Well, it provides the cost of all of the initiatives, as I -- as well as the benefits that our customers are benefiting from, from these investments.

Q When I say benefit/cost analysis, do you understand what that term -- what would you say that term means in the transmission-distribution context?

A So, the way we look at, again, reliability for our customers is the investment that we have to make in order to provide high levels of reliability to our customers, those investments, and what they total to be and, ultimately, what the end result is for those investments, which is the benefits our customers realize in getting superior reliability. That's my definition of that.

Q Okay. And this filing includes the costs that FPL has spent and the -- the reliability improvements.

Does it include any analysis of whether those costs are justified based on the improvements that are being achieved?

A It doesn't in that report, nor is it --

Q Okay.

A -- required.

(Whereupon, Vote Solar/CLEO's Exhibit No. 5 was marked for identification.)

Q Okay. Now, in the second part of the response, you direct us to company witness Michael Jarro's rebuttal testimony in its storm-protection plan proceeding, right?

A Correct.

Q And we've provided an excerpt of that testimony where Witness Jarro addresses the need for a cost-benefit analysis.

Do you have that?

A I have that. Can you highlight what -- what part of his testimony you're referencing?

Q Sure. Are you familiar with this testimony?
A I am.
Q Okay. I'm specifically referring to the portion beginning at Page 14 with the header, "OPC's request for further cost-benefit analyses and storm-damage assessment modeling for FPL's SPP are not appropriate or necessary."
What does --
A It's on Page 14. What -- what line was that?
I'm sorry. I didn't mean to cut you off.
Q Oh, I was just reading the -- the header at the top of the Page 14.
A Oh, okay. Okay. I see that.
Q And in this section, Witness Jarro is stating that: Cost -- a cost-benefit analysis is not necessary for the storm-protection plan, right?
A Is there a specific line in his testimony that -- that you're referencing when he -- when he said that?
Q Sure. Starting on Line 23 of Page 14 --
A Okay.
Q -- it says: Section 366.96, F.S., and Rule 25-6.030, F.A.C., do not prescribe or require a traditional cost-benefit analysis or cost-effectiveness test for the SPP programs and projects.

Did I read that right?

A Yes, I see that.

Q Okay. In his testimony that you provided as a response to this interrogatory, does he address the need for a cost-benefit analysis for expenditures addressing day-to-day non-storm reliability?

MR. BADDERS: Katie, I'm going to lodge an objection. This line of questions about the SPP are beyond the scope of -- of the rate case, other than the shift that is done in the testimony that move costs from one -- from base to SPP, the -- the details of the SPP are handled in the SPP docket.

MS. OTTENWELLER: I understand that, but this witness provided a link to this rebuttal testimony in response to an interrogatory about non-storm-related cost-benefit analyses.

So, I'm really asking about the basis for providing this, and I don't think I'm planning to go into the storm-protection-plan issues.

MR. BADDERS: I'm not instructing him to not answer. I'm just --

MS. OTTENWELLER: Okay. Fair enough.

THE WITNESS: I apologize. Can you restate the question?

BY MS. OTTENWELLER:

Q Sure. Does this testimony address cost/benefit analyses for day-to-day non-storm reliability?

A Subject to check, I believe the testimony for the SPP was specific to what the legislative body had passed, and the rulemaking was developed at the Commission for resiliency to the system to ultimately lower the outage-restoration times and ultimate costs as it relates to an extreme hurricane weather event.

Q So, when you say in your response that this link provided below is a generally-applicable description of how cost-benefit analyses relate to reliability programs, that would only be specific to storm expenditures, right?

A I apologize. Can you say it one more time?

Q So, when you state that the link provided below is a generally-applicable description of how cost/benefit analyses relate to reliability programs -- this link only addresses storm-related reliability programs, right?

A Correct. The link goes to the testimony that was filed in the storm-protection plan, which, again, highlighted, as -- as you referenced, the -- the -- the reference to not requiring kind of the traditional cost/benefit analysis as part of that filing.

Q So, is it your testimony that FPL does not have to conduct a traditional benefit/cost analysis for day-to-day reliability programs?

A Correct. I believe my response is that we are required to make a filing with the Commission of what expenditures we have for reliability, and we do that in our annual reliability report. And it also highlights the tremendous benefits that our customers receive from those investments, which is improved reliability.

Q I'm sorry. I just want to clarify, when you said "correct," were you saying your testimony is that FPL does need to conduct a traditional benefit/cost analysis of day-to-day reliability programs?

A No. What we're required to do is to -- to demonstrate that level of investment that we're requesting is prudent and in the best interest of our customers.

Q Okay. And has FPL conducted a traditional benefit/cost analysis of the day-to-day reliability expenditures in this proceeding?

A No, we haven't and, again, as I stated, it's our -- our request is the investment that we need to serve our customers high levels of reliability, and that the investments are prudent and in the best interest of our customers.

MS. OTTENWELLER:

I next want to turn to your testimony related to growth expenditures. And I believe this starts on Page 37 of your testimony.

And while you're turning there, Russell, I'd say I probably have another 20 minutes of questions. Would it be helpful to take a break or would y'all like to continue?

MR. BADDERS: Yeah, we can do that. And, I guess, while we're -- we're looking at time, I'm not sure who else, as far as intervenors, are going to have questions today. So, I guess, when we come back, if we can kind of maybe get a feel for that and see how long we may actually have today.

MS. OTTENWELLER: That sounds great. So, a five-minute break -- would that be helpful?

MR. BADDERS: That will work.

THE WITNESS: Thank you.

MR. BADDERS: Thank you.

MS. OTTENWELLER: Thank you.

(Brief recess.)

BY MS. OTTENWELLER:

Q Okay. So, turning to your testimony on transmission-and-distribution expenditures related to growth, on Page 37 of your testimony, you state the

company is requesting 5.86 billion of base capital from 2019 to 2023, correct?

A Correct.

Q And you describe these expenditures on Pages 38 and 39 to include the installation of new service lines for 425,000 new service accounts by 2023, correct?

A Correct.

Q And also including expansion and upgrades of transmission-and-distribution facilities and infrastructure?

A Correct.

Q And other large major construction projects and new street-light systems.

A Correct.

(Whereupon, Vote Solar/CLEO's Exhibit No. 6 was marked for identification.)

BY MS. OTTENWELLER:

Q I want to direct you to the company's response to CLEO/Vote Solar POD44.

A Okay. I have it.

Q In Subparts A through C, we requested additional details to support the company's request for growth capital, correct?

A Correct. Yeah, it's -- it looks like the way the question was phrased was to ask for -- for various components to these service accounts and the other -- new street lights and major construction projects to break that down.

Q And your response referred to a file titled "Rate Case Backups For Testimony," right?

A Correct.

(Whereupon, Vote Solar/CLEO's Exhibit No. 7 was marked for identification.)

BY MS. OTTENWELLER:

Q We provided that document this morning as an exhibit. Do you have that available?

A I do.

Q And can you describe what this document is, if you're familiar with it?

A It appears to be a further breakdown of some of the investments that are being requested as part of my testimony.

Q Is there anything in this document that wasn't provided in your actual testimony?

A Can you state that again? I'm sorry.

Q Is there anything in this rate-case backup document that was not provided in your testimony?

A Again, it looks like a -- just additional levels of detail; so, in terms of just looking at the --

the actual investment by category. And they seem to align with what's in my, you know, testimony, so --

Q Okay.

A -- seems like they're...

Q And did you file any other supportive documents relating to this portion of your testimony in any discovery responses to parties in this proceeding?

A I'm not sure. I'd have to probably do that review. I'm not sure.

Q Okay. And did you conduct a benefit/cost analysis of these growth expenditures?

A Again, we provided, as part of my testimony, as -- as you see in this exhibit as well as represented in my testimony -- what the investments we were proposing to make.

And we've spent, obviously, quite a bit of time talking about just the benefit that those will provide, which is, again, the high level of reliability that our customers are already receiving as well as continuous improvement.

Q I want to turn back to CLEO/Vote Solar Interrogatory No. 93 that we discussed earlier. Do you still have that available?

A 93, you said?

Q Yes.