CLF 1-1

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	**:**
d/b/a RHODE ISLAND ENERGY'S ELECTRIC	**:**
INFRASTRUCTURE, SAFETY, AND RELIABILITY	**: DOCKET NO. 22-53-EL**
PLAN FY 2024 PROPOSAL	**:**

REPORT AND ORDER

I. Overview

On December 22, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy (RI Energy or Company) filed with the Public Utilities Commission (Commission) its proposed Electric Infrastructure, Safety, and Reliability Plan (Electric ISR Plan) for FY 2024.[1] RI Energy indicated that the Division of Public Utilities and Carriers (Division) was not in agreement with the proposed plan.[2,3,4]

The proposed FY 2024 period was designed to set a budget for the period April 1, 2023 through December 31, 2024, a twenty-one month period.[5] This is the first ISR plan filed by the Company since the acquisition by PPL Holdings, LLC (PPL).[6] Whereas National Grid's fiscal year ran from April 1 through the following March 31, PPL's matches the

[1] The FY 2024 Electric ISR Plan and all of the documents referenced herein can be found on the Commission's website at: https://ripuc.ri.gov/Docket-22-53-EL.
[2] Filing Letter at 1 (Dec. 22, 2022).
[3] Rhode Island Gen. Laws § 39-1-27.7.1(d) provides two pathways for Commission review. The first is where the Company files a plan that was negotiated with the Division. The second is where the Company and Division are unable to reach an agreement. In that instance, the Company files its proposal and the Division acts in a more traditional adversarial role. This is the first time the Commission has reviewed a disputed Electric ISR Plan since passage of the law in 2010.
[4] The RI Attorney General and OER intervened in this matter.
[5] Filing Letter at 2.
[6] The Narragansett Electric Company was previously doing business as National Grid. On May 25, 2022, PPL Rhode Island Holdings, LLC, an indirect wholly owned subsidiary of PPL Corporation, acquired 100 percent of the outstanding shares of common stock of The Narragansett Electric Company, now doing business under the name Rhode Island Energy.

Calendar Year. According to RI Energy, the twenty-one month plan was designed to realign the ISR plan with the Company's new fiscal year.[7]

After conducting a preliminary review of the filing and R.I. Gen. Laws § 39-1-27.7.1, the Commission requested briefs from the Company and Division addressing whether the twenty-one-month proposal was consistent with the law. The Company and Division disagreed about the proper interpretation of the law. After a review of the briefs, the Commission required the Company to submit a revised twelve-month budget for the fiscal year referenced in the Company's tariff. The proposed revised budget was filed on January 27, 2023. The new 12-month budget represented a 68% increase in the capital budget over the FY 2023 approved capital budget.

Following discovery, testimony from the Division, the filing of a position statement from the Attorney General, additional revised budget filings, and several days of hearings, on March 29, 2023, the Commission ultimately reduced the revised capital budget that was provided during the hearings, by $53,461,000.[8,9] The adjustment resulted in an approved revenue requirement of $55,418,057, requiring an incremental fiscal year upward rate adjustment of $5,696,733. This will support a FY 2024 Electric ISR Plan capital budget of $112,329,000, a vegetation management budget of $13,950,000, an infrastructure and maintenance (I&M) budget of $738,000, and other expense of $425,000.[10]

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[7] Labarre Test. at Bates page 7.

[8] Attachment 3c Second Supplemental. The Attorney General and Office of Energy Resources intervened but did not present witnesses.

[9] Specifically, the Commission removed a new Grid Modernization category and funding, redirectined a small amount of funding to the Asset Condition category for a small number of reclosers that can properly fall within that category. The Commission also followed Mr. Booth's recommendation and reduced the budget for major projects within the Asset Condition category by $10 million finding that the remaining budget allowance is sufficient to support a reasonable implementation schedule and is still greater than what was allowed in FY 2023. The Commission rejected the new Mainline Recloser program that was proposed within the System Capacity and Performance budget, finding that it was not adequately supported by the record for inclusion in the FY 2024 budget. The result was a $53.461 million reduction to the FY 2024 capital budget.

[10] Compliance Filing, Section 5:Attachment 1(C); Compliance Filing – Effective Rates April 1, 2023, Docket No. 22-53-EL- Electric ISR FY 2024 Budget (Mar. 30, 2023).

II. Threshold Issue Relating to the ISR Fiscal Year

A. The Statutory and Tariff Language Relating to "Fiscal Year"

R.I. Gen. Laws §39-1-27.7.1(d) requires each gas and electric distribution company prior to the beginning of the fiscal year to consult with the Division of Utilities and Carriers (Division) regarding its ISR spending plan for the following fiscal year. Specifically,

> (d) Prior to the beginning of *each fiscal year*, gas and electric distribution companies shall consult with the division of public utilities and carriers regarding their infrastructure, safety, and reliability spending plan for the *following fiscal year*…. (emphasis added).

Fiscal year is not defined in the statute, nor does the statute require that the fiscal year be that of the distribution company. Prior to the current year, when The Narragansett Electric Company was owned by National Grid, the annual plan was filed in December and requested rates for effect April 1 through March 31. This coincided with the US GAAP fiscal year of National Grid and was consistent with the tariff, RIPUC No. 2199 which states:

> "Current Year" shall mean the fiscal year beginning April 1 of the current year and running through March 31 of the subsequent year during which the proposed CapEx Factor and O&M Factor will be in effect.
>
> The CapEx Factors shall recover the Cumulative Revenue Requirement on Cumulative CapEx as approved by the Commission in the Company's annual Electric ISR Filings. The CapEx Factors shall be applicable for the twelve-month period commencing April 1.
>
> "O&M Factor" shall mean the per-kWh factor for all rate classes, except for Rate B-32, designed to recover the Forecasted I&M Expense and Forecasted VM Expense for the Current Year, as allocated by the O&M Allocator, based on Forecasted kWh for the Current Year for each rate class. For Rate B-32, the O&M Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for the rate class.
>
> The O&M Factor shall recover the sum of the annual Forecasted I&M Expense and Forecasted VM Expense as approved by the Commission in

> the Company's annual Electric ISR Filings. The O&M Factor shall be applicable for the twelve-month period commencing April 1.

In May of 2022, PPL acquired Narragansett Electric and began doing business as Rhode Island Energy. Unlike National Grid's fiscal year which ran from April 1 through March 31, RI Energy's US GAAP fiscal year coincides with the calendar year, consistent with the financial accounting schedule utilized by its parent Company – PPL.

B. Commission Request for Briefing on Fiscal Year Issue

On January 3, 2023, the Commission directed the Company and the Division to provide legal briefs in both this docket and Docket No. 22-53-EL (Electric ISR) addressing the following issue:

> How are the Proposed 21-month plans that span two fiscal years (FY 2023 and FY 2024) filed as the FY 2024 Proposed Electric Infrastructure Safety and Reliability Plan and the Proposed FY 2024 Gas Infrastructure Safety and Reliability Plan made by Rhode Island Energy on December 22, 2022 consistent with the statutory requirement to file a spending plan for the following fiscal year?

The Company's brief argued that the extended fiscal year (21 months) was consistent with the statute and appropriate for a number of reasons. First, it asserted that fiscal year is not defined by statute and is flexible. It argued that it is common when there has been a change in company control to use an extended fiscal year, and that a company can define its own fiscal year. Next it argued that there is no requirement in the statute that mandates that the ISR Plan cover a period of twelve months. It maintained that the statutory language focuses on the contents of the ISR Plans more than the time period they cover. It further argued that because of the dates in the approved FY 2023 ISR Plan filed by its predecessor, National Grid, cover the April 2023 to March 31, 2024 period, it proposed the 21-Month Plan to align with the RI Energy fiscal year and believed that to be appropriate.[11]

The Company argued that its proposed 21-Month fiscal year will not interfere with the annual reconciliation filings it plans to file in August of 2023 in relation to the FY 2023 Plan and in 2025 following the end of RI Energy's FY 2024 Plan period. It maintained that while the section of the statute addressing revenue decoupling specifies an "applicable twelve-month period", the section related to the ISR Plan merely states "fiscal year". It argued that this is evidence that the legislature did not intend that the term "fiscal year" be limited to a 12-month period.[12]

Finally, the Company argued that being required to submit two ISR Plans for the 21-Month period would be unduly burdensome, unnecessary, and not in the best interest of customers. Because it would require two plans to be submitted within only a "few months", the Company alleged that the Division, the Commission, and other interested parties will be required to engage in additional review to an already "congested regulatory calendar." Moreover, the Company argued that it is unnecessary because the Company's submission of two plans with shorter time periods would not change the content of what was proposed in the 21-Month Plan but would result in a double review of the Plan and a doubling of the parties' and the Commission's time and effort. RI Energy asserted that requiring multiple filings with shorter periods may also have a negative impact on customers. It provided that collecting the revenue over a period of 21 months would offer greater rate stability than if the Company was required to file a 9-Month and a 12-Month plan. Lastly, it noted that its proposal to extend the fiscal year is a one-time occurrence.[13]

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[11] RI Energy Brief at 5-9 (Jan. 17, 2023).
[12] *Id.* at 9-11.
[13] *Id.* at 11-13.

The Division, in its brief stated that since the inception of the ISR, it has never consulted with the Company on a plan or budget other than for a 12-month fiscal year. The Division argued that the language of the statute is clear and the word "each" before "fiscal year" is a clear indication that the consultation process engaged in by the Division with the Company occur each and every year. The Division asserted that the phrases "following fiscal year" and "prospective fiscal year" in the statute best align with the April 2023 through December 2023 period and dovetails with the annual nature of the rate reconciliation preapproved budget. The Division maintained that it lacks authority to skip the consultation process, to reach an agreement on multiple fiscal year ISR budgets or investments made in multiple fiscal years, to review and approve an ISR plan for a year beyond the fiscal year, or to set an ISR factor beyond the 12-month period of the "prospective fiscal year."[14] Finally, the Division argued that setting an ISR electric rate based on multiple fiscal years will improperly require customers to pay for projects prematurely.[15] In addition to its legal arguments, the Division recommended that the Commission only review and set factors for the proposed 9-Month budget, that it require the Company to file an updated CY 2024 ISR Plan by September 1, 2023, that it establish a procedural schedule, and that a CY 2024 budget only be established after review of the filing and the Division recommendations.[16]

C. Open Meeting Decision Regarding Fiscal Year Definition

At an Open Meeting on January 20, 2023, the Commission considered the arguments made by the Company and the Division.[17] The Commission noted that the term

[14] Division Brief at 3-5 (Jan. 17, 2023).
[15] *Id.* at 5-7.
[16] *Id.* at 7-8.
[17] Neither OER nor the Attorney General took a position on the issue.

"fiscal year" is not defined in the statute, nor does the statute specify that "fiscal year" must be the fiscal year of the Company. For more than ten years and since the inception of the law, the Narragansett Electric Company has used an April 1 through March 31 fiscal year which is set forth in the Company's approved tariffs. Coinciding with a fiscal year that commenced on April 1 was beneficial for several reasons. Construction on the distribution system usually commences after the winter season ends. Another benefit was that the Commission's review of the ISR budget would occur during the first quarter of the year as opposed to the last quarter when the Commission has a number of complex matters and annual filings before it both from the Company and other regulated utilities. From the Company's financial accounting perspective, the alignment of an ISR fiscal year to the Company's US GAAP fiscal year also was convenient and efficient to National Grid.

The Commission noted that at no time prior to submitting the 21-Month Plan to the Division on October 21, 2022 or prior to filing it with the Commission on December 22, 2022, did the Company request a change to or waiver from the time period set forth in its current tariff. Instead, it chose to propose a tariff change in the December 22nd filing, requesting a change from a fiscal year spanning April through March, to a 9-month period of April through December. This presupposed the Commission would approve the request to change the tariff, even though the Company was aware of the Division's objection to the 21-Month fiscal year prior to the time that it filed the 21-Month Plan with the Commission.

As the Company acknowledged, "fiscal year" is not defined by the statute. Moreover, the statute does not refer to "fiscal year" as "the Company's fiscal year". It only specifies "each fiscal year" and "the prospective fiscal year". Nor is "fiscal year" associated with or limited to a company's financial reporting requirements within the statute. In fact, the Company recognized the lack of limitations in its brief when it argued:

> [t]he plain language of [the statute] focuses on the *contents* of the ISR plans more than the specific timeline they cover. The reference to "fiscal year" provides a framework for the Company to ensure it:
> (a) regularly plans for necessary safety and reliability investments;
> (b) consults with the Division about these proposed investment expenditures; and
> (c) has a deadline by which to file its ISR plans.

While it may be convenient for RI Energy to have the ISR fiscal year match its US GAAP accounting fiscal year on a calendar basis, it is not a legal requirement under the law – a point which was effectively conceded by the Company when it proposed a 21-month period as its 2024 fiscal year and proposed a tariff change that specified a spending segment of only 9 months.

This Commission has broad authority to define the ratemaking rules and the processes for evaluating proposals that impact rates provided that the result is fair and reasonable. In that regard, it is reasonable for the Commission to consider administrative efficiency, resource constraints, the timing of when rate increases that go into effect, and how the timing would affect ratepayers. In that regard, changing the ISR fiscal year to match the RI Energy calendar year would not be inconsequential to the regulatory process and the Commission's ability to properly review the filing. The Commission has a number of complex matters before it during the fourth quarter of the calendar year which is when the ISR Plan would need to be filed and reviewed if the ISR fiscal year was shifted to a calendar year.[18] Changing the ISR fiscal year to what has been proposed would disrupt the administrative efficiencies built into the current framework and disrupt the regulatory

[18] R.I. Gen. Laws §39-1-27.7.1(d)(4) states "[i]f the company and the division cannot agree on a plan, the company shall file a proposed plan with the commission and the commission shall review and, if investments and spending are found to be reasonable needed to maintain safe and reliable distribution service over the short and long term, approve the plan within ninety (90) days."

process.[19] Moreover, it would adversely impact the review process of not only the Company's ISR Plan but of other matters before the Commission by diverting necessary time spent reviewing those matters to the ISR Plan. Moving to a calendar year also would result in an additional rate increase being imposed on ratepayers in the middle of the heating season – a time when heating customers are often facing increases from the annual winter cost of supply.

The Commission has a duty to both the utility and ratepayers to assure review of the proposed spending levels are scheduled in a manner that is conducive to a thoughtful and complete review and that is not rushed by the challenges of end-of-the-year requirements. The Commission also has the authority to consider timing that affects the size of rate increases. In contrast, while it might be more convenient for the Company to be able to align its capital budget plan with the financial review that the Company performs each year at its parent level at PPL, such convenience does not outweigh the detriment to the regulatory process caused by a shift to a calendar year review. There is no financial loss to the Company and the Company retains a reasonable opportunity to recover all of the costs relevant to the applicable capital spending plan if the current fiscal year is retained.

Finally, the Commission made a finding that the Company failed to comply with the terms of its own tariff. Thus, the filing was deficient. As a result of the tariff non-compliance and the other considerations identified above, the Company was ordered to make supplementary filings of its schedules and budgets to align with the tariff condition presently in effect – April 1 through March 31.

[19] It is worth noting that the Company made an argument based on administrative efficiencies when it proposed one 21-month planning period instead of two, arguing that it was unduly burdensome on the parties and customers. RIE Brief at 11 (Jan. 17, 2023).

While this decision was ultimately founded upon a finding that the Company's filing was inconsistent with the tariff, the Commission emphasizes that the decision was not driven merely by a tariff-based technicality. The Commission's decision also is founded upon the reasonableness of leaving the current ISR fiscal year in place for the practical reasons given above, notwithstanding the fact that the Company's US GAAP fiscal year is based on the calendar year.[20] This was not a decision by the Commission which directed the Company to change its financial accounting fiscal year for purposes of US GAAP. Rather, it was a decision that was limited to specifying the period over which the Commission will define the review period over proposed capital spending plans under the ISR which will ultimately result in rate changes. The Company's actual fiscal year for financial reporting that was chosen by the Company for US GAAP purposes remains unchanged.

II. Rhode Island Energy's Revised Filing

A. Revised Budget

On January 27, 2023, the Company submitted a Revised Electric ISR Plan covering the 12-month period April 1, 2023, through March 31, 2024. The initial revised proposed revenue requirement for the period was $58,694,860 to support a capital budget of $176,318,000 plus Operations & Maintenance (O&M) for vegetation management; Inspection & Maintenance (I&M); Volt/Var Optimization and Conservation Voltage Reduction Expansion (VVO/CVR); and a new O&M category for grid modernization investments.[21] The Company subsequently removed the O&M related to grid modernization

[20] The Commission notes that this same reasoning relating to the definition of the fiscal year equally applies to the electric ISR which was decided and considered in Docket No. 22-53-EL at the same time that the decision was made in this docket.
[21] Supplemental Budget (Jan. 27, 2023).

and in another filing, reduced the proposed capital budget by $10.5 million, specifically in the Grid Modernization category, due to supply chain constraints. The proposed second supplemental capital budget totaled $165,790,000.[22] The revised Vegetation Management budget was proposed at $13,950,000.[23] The remainder of the revised non-capital budget totaled $1,163,000 after the Company removed its request for O&M related to the Grid Modernization investment proposals.[24]

The Company included six spending categories within the capital investment budget: to meet state and federal regulatory requirements applicable to the electric system (Customer Request/Public Requirement);[25] to repair failed or damaged equipment (Damage Failure);[26] to address load growth/migration; to provide reliability and power quality in the face of growing/shifting customer demands on the system (System Capacity and Performance);[27] to replace assets if their condition impairs reliable and safe service to customers, prioritized based on likelihood of failure (Asset Condition);[28] and a new category "to meet evolving operation and reliability needs, customer expectations, and State clean energy goals" (Grid Modernization).[29]

The proposed revised budget for the Vegetation Management Program represented an increase of approximately $2.1 million from the spending approved in the FY 2023 Electric ISR Plan.[30] The primary reason for the increase is an increase in the cycle trimming budget, which will now include an enhanced trimming and risk reduction component based on a new

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[22] Second Supplemental Budget (Mar. 21, 2023); Hr'g. Tr. at 43-44 (Mar. 8, 2023).
[23] Supplemental Budget (Jan. 27, 2023).
[24] Second Supplemental Budget (Mar. 21, 2023); Updated Supplemental Budget (Mar. 8, 2023).
[25] Initial ISR Filing at Bates page 89.
[26] *Id*. at 90.
[27] *Id*. at 101.
[28] *Id*. at 96.
[29] *Id*. at 92.
[30] Supplemental Budget (Jan. 27, 2023); Initial ISR Filing at Bates page 165.

type of data analysis. Instead of a set recurring cycle for trimming, the Company will review the circuit locations and actual growth in its prioritization and if there are hazards found on a circuit such as heavy overhand, dying trees, structurally deficient trees, the Company will include a targeted "on-cycle" risk reduction work instead of relying only on "off-cycle" risk reduction. This, in turn, should reduce the need for as much work under the "pockets of poor performance," something for which the Company was projecting lower spending.[31]

The Second Supplemental Revised budget for I&M spending included capital amounts already accounted for above plus $738,000 for O&M costs related to the I&M program, including inspections, voltage testing, and the contact voltage program. Finally, there were" other" O&M expenses in the amount of $425,000, related to the ongoing long-range system capacity load study and expansion of the VVO/CVR program.[32]

The Company agreed to provide the Commission with quarterly reports on the progress of executing the ISR Plan as well as an annual report at the time the Company files its annual reconciliation.[33] RI Energy provided the Commission with a benefit cost analysis based on the Commission's Docket No. 4600 Guidance Document and Framework to support four new budget proposals or a revised scope.[34]

B. Development of the ISR Factor

In written testimony, Peter Blazunas, a consultant from Concentric Energy Advisors, explained that the overall ISR Factor embedded in distribution rates contains two mechanisms: (1) an Infrastructure Investment Mechanism to recover costs associated with incremental capital investment and (2) an O&M Mechanism to recover O&M expenses

[31] Initial ISR Filing at Bates pages 160-164.
[32] *Id*. at Bates pages 167-169; Second Supplemental Budget (Mar. 21, 2023).
[33] *Id*. at Bates page 34.
[34] *Id.* at Bates 128-158.

related to inspection and maintenance and vegetation management activities. To design the Infrastructure Investment Mechanism and develop the incremental capital investment, following Commission review of a cumulative revenue requirement, RI Energy applies a rate base allocator that was developed in the most recently approved cost-of-service study. These become the Capital Expenditure Factors included in each rate class's respective overall ISR Factor. Similarly, the O&M mechanism is designed to allocate the inspection and maintenance and vegetation management expenses to rate classes based on the percentage of total distribution O&M expense allocated to each rate class in the most recent cost-of-service study. Within each rate class, RI Energy calculates a per unit charge based on kilowatt hour (kWh) usage for non-demand classes and on a kilowatt (kW) basis for demand classes.[35]

Each year, by August 1, the Company proposes Capital Expenditure reconciling factors and an O&M reconciling factor to become effective on October 1 for the following twelve-month period. The reconciliation compares the actual cumulative revenue requirement to actual billed revenue generated from the Capital Expenditure Factors included in the prior year's overall ISR Factor. Any over- or under-recovery is refunded to or collected from customers through the Capital Expenditure Reconciling Factors. The O&M reconciling factor will compare the actual I&M and vegetation management O&M expense to actual billed revenue generated from the O&M factors. Any over- or under-collection of actual expense is refunded to or collected from customers through a uniform per kWh charge applicable to all rate classes.[36]

[35] Blazunas Test. at Bates 277-79, 280-82.; Section 6: Rate Design; For G-02 and G-32/B-32 customers, whose charges include both demand and usage, the Capital Expenditure Factors and O&M Factors are designed "to not significantly change the relationship between the existing charges and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts." Crary Test. at 195.
[36] *Id*. at Bates 279-80, 282.

III. Approved FY 2024 Electric ISR Budget and Revenue Requirement

Following evidentiary hearings conducted over four full days during which the Commission heard testimony from eight Company witnesses[37] and Mr. Booth, the Commission considered the evidence at an Open Meeting held on March 29, 2023. As a result of its review of the evidence in the record, the Commission made several modifications to the budget resulting in an approved revenue requirement of $55,418,057, requiring in an incremental fiscal year upward rate adjustment of $5,696,733. This will support a FY 2024 Electric ISR Plan capital budget of $112,329,000, a vegetation management budget of $13,950,000, an infrastructure and maintenance (I&M) budget of $738,000, and other expense of $425,000.[38]

A. Preliminary Observations

At the outset, before addressing the specific decisions in this case, the Commission notes that in this first ever contested ISR Plan filing, there was an undertone of a breakdown in respect during the course of the Division's preliminary review. This may arise in part from either the change in company ownership, the shift in organizational control to more local authority, or a combination of both. The Commission recognizes that there is likely a benefit from a return to more local authority over the planning and investment decisions of the utility compared to that which existed under the National Grid paradigm. The Commission has

[37] Alan LaBarre, Senior Director of Electric Operations; Nicole Begnal, ISR Manager; Christopher Rooney, Manager of Distribution and Transmission Forestry; Kathy Castro, Director of Asset Management and Engineering; Ryan Constable, Engineering Manager in Distribution Planning and Asset Management; Wanda Reder, Consultant; Stephanie Briggs, Senior Manager of Revenue and Rates; Jeffrey Oliveira, Regulatory Programs Specialist; Peter Blazunas, Consultant, and Daniel Glenning, Director of Projects and Construction Management. Andrew Elmore, Vice President – Tax, and Natalie Hawk, Director of Tax Accounting and Reporting also filed testimony but did not attend the electric ISR hearing. Mr. Elmore and Ms. Hawk did testify on the identical issues at the FY 2024 Gas ISR hearing and the Commission took administrative notice of their testimony for this matter.

[38] Compliance Filing, Section 5:Attachment 1(C); Compliance Filing – Effective Rates April 1, 2023, Docket No. 22-53-EL- Electric ISR FY 2024 Budget (Mar. 30, 2023).

confidence that the planning and engineering teams at the Company are competent, capable, and enthusiastic about constructing and maintain a safe and reliable electric system.

The Company, however, must accept the validity of the concerns raised by the Division through its consultant, Mr. Booth. Mr. Booth has a great deal of credibility with the Commission and serves as a valuable resource to balance the Company's enthusiasm. He raises important contextual concepts for consideration of the Commission which does not have the benefit of its own engineering staff. His testimony in this case also represented the balance of ratepayer funds toward the state policy goal of "just and reasonable rates" which, based on testimony from public officials, means, to some extent, affordability. The Company's initial proposal represented a significant increase in capital investment over the next two to five years, coupled with a separate Advanced Metering Functionality proposal, and an all-or-nothing presentation by the Company. These factors all combined has led the Commission to consider whether there are appropriate cost controls and sensitivity to rate impacts within the Company.[39]

The Commission is also concerned with certain testimony from Company witnesses at the hearings that suggested the ISR budget represented the only investment and pathway for the Company. Such a stance ignores basic ratemaking principles and inappropriately suggests that it is the Commission who decides whether an investment is needed for safety and reliability. It is the Company that has the burden of proving that its investment budget is reasonable and supported by the evidence. It must show that the investment is needed in the short- and long-term to provide safe and reliable service. It must identify the problem on the system, the location on the system, how the investment will solve the stated problem, and how

[39] The Commission has opened a separate docket (23-34-EL) to review the budgeting and planning processes for ISR in the future. To date, the discussions with the Company have been productive and in the cooperative spirit.

the investment is consistent with the Least Cost Procurement Standards. It is then Commission that determines whether the Company has met its burden of proof to include the investment in its revenue requirement for preferential rate treatment.

Delay of recovery of an expense from the special ratemaking treatment provided by ISR is not a disallowance of cost. Instead, the Company can seek to include that investment in its rate base for rate recovery in its next rate case. Thus, if the Company, despite a Commission ruling determines that it must make an investment in the system that is prudent, it has the legal obligation to do so and it may request cost recovery no later than the next rate case. The Company appeared to assert that if it is level funded, it will not invest in a necessary component of the system. This position appears to be an inappropriate attempt to shift risk from the Company onto the regulator for management decisions.

The ISR statute, adopted in 2010 is an exception to the normal ratemaking methodology and needs to be applied judiciously to ensure a reasonable pace of investment necessary to achieve safe and reliable service. That is how the ISR has been working and the Company's enthusiasm for accelerating the investment in new technologies and automation needs to be reviewed in this context.

B. Grid Modernization

The Company proposed a new capital spending line item for "Grid Modernization" within the non-discretionary budget. This new subcategory of spending comprised 25% of the overall budget.[40] The Company witnesses stated, "[t]hese investments are needed now because of deteriorating reliability trends increased operational risk present with the high DER adoption rates reinforced by the State Climate Mandates, growing interconnection queues,

[40] Proposed FY 2024 Electric ISR Plan at Bates 31.

and supply chain delays and material availability."[41] The Company contended that these investments were, like Customer Requests/Public Requirements and Damage Failure subcategories, driven by forces outside of the Company's control in both scope and timing. Thus, the Company categorized them as non-discretionary.[42] Under the current tariff language, such a designation would allow the Company to exceed budgeted amounts and receive full cost recovery. In contrast, discretionary spending is subject to certain limitations on cost recovery.[43]

The Division, through its witness, Gregory Booth, P.E., recommended removing the entire Grid Modernization budget, challenging the Company's categorization of the spending as non-discretionary, the stated need, and the contentions about worsening reliability. He stated that the proposal was "premature and proactive absent any justification for early advancement of capital spending prior to implementation of AMF and a comprehensive communication system capable of communicating both within Rhode Island and back to the PPL control center."[44] He further contended that, "The $45 million of grid modernization spending proposed is premature and accomplishes little toward reliability enhancement or DER enablement. Until AMF is fully functional, and a comprehensive telecommunications system is fully functional, grid modernization equipment will have no real functional benefit."[45] With respect to reliability, Mr. Booth noted that the Company's reliability results have remained and continue to remain well within the Commission's SAIDI and SAIFI guidelines.[46] He challenged the Company's position that grid modernization investments are

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[41] *Id*. at 32.
[42] *Id*.
[43] *Id*. at 178-80.
[44] Booth Test. at 10-11.
[45] *Id*. at 13.
[46] *Id*. at 14.

required now to integrate and manage forecasted DER because such investments have not been required to date and given availability of land and conservation concerns, the proliferation of large DER investments is likely to slow.[47] Furthermore, he opined that the new vegetation management approach would continue to improve the currently acceptable reliability statistics.[48] In short, Mr. Booth argued that the proposed ISR Plan failed to justify the immediate need for the advancement of grid modernization investments, particularly absent an approved Grid Modernization Plan.[49]

The Company responded to numerous discovery requests and hearing questions directed toward their claim of need in the short- and long-term for these investments. The questions also focused on the Company's contentions that their reliability metrics were experiencing a declining trend. After a review of the entire record, the Commission unanimously found that RI Energy had failed to meet its burden of showing that the proposed investments were needed to meet short-term safety and reliability measures. Furthermore, with respect to long-term need, the Commission found that there was no immediate need for the investments to meet foreseeable long-term needs.

Specifically, the Commission found that the evidence does not support the Company's contentions that: (1) there is a downward trend in reliability; (2) that there is a near term need for the proposed Grid Modernization investments related to visibility and control of DER; nor (3) that Grid Modernization investments are needed to meet the Act on Climate or Renewable Energy Standard. Therefore, the evidence did not support an urgent need to approve funding through ISR of investments in the Grid Modernization category prior to consideration of a Grid Modernization plan.

[47] *Id*.
[48] *Id*. at 15.
[49] *Id*.

Furthermore, the Grid Modernization plan description provided by the Company is not a plan based on realistic forecasts, but rather, on scenarios to test the system under varying conditions.[50] In other words, the Company presented the Commission with "if all of these things happen, here are the investments we will need" instead of "here is what we forecast will happen on the system and the resulting investments we will need." Therefore, the Company did not present a credible plan for funding approval through the ISR.

Instead, before the Company can meet its burden of proof, it needs to present realistic forecasts of what is likely to happen on the system as a precursor to the proposed solutions. The all-or-nothing approach taken by the Company in its proposal failed to recognize the realities of needing to balance investments with ratepayer impact.[51] As part of all ISR proposals, the Company needs to prove the near and long-term need based on evidence; the necessary pace of investment; the location of the need for the investment; and the proper sequencing in order to avoid imprudent expenditures from inefficient or premature investment plans.

Although the Company repeatedly stated that there is a declining trend in SAIFI, the evidence did not support this contention. The information presented in the responses to Record Requests 3 and 9 show a randomness to the Company's SAIFI performance rather than a declining trend.[52] The Company has consistently met its service quality metrics over the past several years and calendar year 2022 showed improvement in reliability.[53]

Additionally, the Company failed to show that decline in reliability is related to the visibility and remote control on the system. Instead, Attachment 4, Charts 1 and 8 of the

[50] Hr'g. Tr. at 563-69; 571; 599-600; 665-66; 751-55, 756.
[51] Hr'g. Tr. at 602-07; 617-19.
[52] RI Energy's Responses to RR-3 and RR-9.
[53] Proposed FY 2024 Electric ISR Plan at Bates 124; Hr'g. Tr. at 575-76.

Electric ISR Plan show a correlation of reliability to the challenges with tree mortality related to the Spongy Moth (formerly called the Gypsy Moth) infestation of a few years ago.[54] The Company has responded by proposing modifications to the vegetation management that it has claimed will improve reliability by 15%-18%.[55] Reviewing those facts in evidence as a whole, the Commission concluded that there is no trend of declining reliability, that where there are declines in reliability, trees are still a major challenge which the Company proposed to address through modifications to the vegetation management approach. Therefore, the Commission could not find, based on the evidence presented, that the Grid Modernization investments as proposed in this docket are needed to solve the stated problem.

Turning to the Company's stated need for visibility and control because of increased DER on the system, first, there is no support for these investments being anything other than discretionary in nature. While the Company has attempted to portray the need as reactionary, unlike Customer Requests/Public Requirements or Damage/Failure, the nature of the investments are much more in line with System Capacity and Performance or Asset Condition.

Unlike the first two categories, these investments are neither unplanned nor unpredictable events that occur outside of the normal course of the Company's planning and investment processes. The fact that the Company is considering how to automate the system to gain visibility and control is indicative of the fact that the Company can plan for the impact of DER and electrification on the system. The Company defined the purpose of the Grid Modernization category as meeting "the evolving operation and reliability needs, customer

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[54] Proposed FY 2024 Electric ISR Plan at Bates 119, 27; The Company has committed to continuing to track and report on trees removed as a result of pests, particularly because of the ongoing concerns related to the Emerald Ash Borer, another invasive pest.
[55] Hr'g Tr. at 109; Booth Test. at 15.

expectations, and State clean energy goals."[56] The Commission finds this assertion to be inconsistent with the operational realities. To the contrary, the proposals included in Grid modernization are a part of the normal System Capacity and Performance category which is defined as "projects [that] are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers."[57] The proposal of different technologies and solutions to meet the same overall objective does not necessarily change the categorization of investment nor does it change the burden of proof.[58]

In addition, when the Company's witness was asked to identify specific areas on the system where the Grid Modernization investments were needed to provide safe and reliable service, the best the witness could respond is that there are places where the investments would be beneficial, but he could not commit to identifying areas where they are needed.[59] The witnesses testified that the Company has invested in feeder monitors in those areas as part of the strategic DER allowance. And, while the Company may eventually need a more dynamic system to handle hourly load changes as the difference between generation and load gaps exist, the Company's own load forecasts do not support a need in the near or medium term. Load is not forecasted to exceed 1900 MW until 2029 under an extreme scenario. In addition, Figure 10 of the forecasts shows that the potential for gaps becomes more problematic as we move closer to 2036.[60] The Company's witness was unable to identify any areas on the system that have currently have characteristics similar to what might exist in 2036. The Commission cannot approve funding through ISR on a grid modernization plan that was not developed on a real load forecast, but on a stress test under extreme scenarios.

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[56] Proposed FY 2024 Electric ISR Plan at Bates 92.
[57] Proposed FY 2024 Electric ISR Plan at Bates 33.
[58] *See* Hr'g. Tr. at 1011.
[59] Hr'g. Tr. at 669-70.
[60] RI Energy Response to Div 1-14; Attachment Div 1-14 (Figure 10), Bates page 71.

The evidence does not support the Company's contention that grid modernization is needed to meet the Act on Climate or RES mandates. Record Request 24 shows that even if there were no additional DERs over what was commercially operational in Spring 2023, there are enough renewable energy certificates available to meet the 2040 requirements under the Company's load forecast. Therefore, meeting this policy goal is not a driver of investment today.

Finally, Mr. Booth expressed concern that a grid modernization investment category is premature without a grid modernization strategy. The Company filed a Grid Modernization Plan after it filed this ISR Plan. The Amended Settlement Agreement in Docket No. 4770 contemplated action on a Grid Modernization Plan before the Company receives funding approval for an investment strategy. For all these reasons, the Commission finds that the Company failed to meet its burden of proof to include these proposed investments in the FY 2024 ISR budget for funding approval.[61]

C. Asset Condition Adjustments

The Grid Modernization Category included funding for reclosers which, at the hearing, Mr. Booth testified if they were at the end of their useful life, they could be properly included in the Asset Condition category.[62] The Company identified 18 such reclosers. Therefore, the Company shall reallocate $1.3 million from the Grid Modernization category to the Asset Condition category.

Within the Asset Condition category, there is a major projects subcategory that includes specific project. The Commission accepted Mr. Booth's recommendation to reduce

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[61] The Company had proposed Grid Modernization budget line item $35.257M. That amount was denied. However, the Commission ordered the reallocation of $1.3M to the Asset Condition category as noted in the Asset Condition section of this order. The net of these two adjustments is a downward adjustment to the FY 2024 Electric ISR budget is $33,957,000.

[62] Hr'g. Tr. at 1005-1007.

the overall Asset Condition budget by $10 million. The Commission found that the Company's proposed 48% increase to that budget did not hold up against Mr. Booth's challenge. First, the Commission agrees with Mr. Booth that the Company is likely to face challenges completing that much incremental investment. Second, the Company did not adequately analyze different implementation schedules. Finally, the Commission is concerned with the Company's repeated criticism on the Division's focus on ratepayer impact. Such a perspective supports the need for heightened scrutiny of the budgets.

D. System Capacity and Performance

1. Mainline Recloser Program

The Company proposed a new Mainline Recloser Enhancements program to install 100 new reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts. According to the Company, the absence of reclosers on exposed overhead lines and circuits with one or zero reclosers increases customer outages due to the lack of sectionalization and reduces the ability to remotely transfer load during an outage.[63]

The Division did not support funding for the new Mainline Recloser Program, arguing that it was premature, was not supported by a protection study, and not coordinated with RI Energy's other reliability initiatives.[64]

[63] Proposed FY 2024 Electric ISR Plan at Bates 105.
[64] Booth Test. at 58-60. Mr. Booth explained that "reclosers are distribution devices mounted on poles at select locations along circuits. Their primary function is sensing line conditions and acting like a circuit breaker when anomalies occur. If a problem is temporary, reclosers have the capability to open, allow a faulted condition to clear, and then reclose again helping to maintain service continuity. If the fault is not temporary, reclosers in strategic locations can open to protect the faulted section and minimize the number of customers affected by an outage. Reclosers are common equipment on distribution systems and also leveraged by utilities for switching schemes in operations. The Company has hundreds of reclosers on its system, categorized as dark (no communication or remote control), remotely operated (two-way commands), and GMP enabled (cable of network connection for automated schemes). Whether existing, labeled as "Mainline", or "GMP", reclosers are the same equipment and underlying specifications but may be outfitted with varying control technology." Booth Test. at 57.

The Company initiated this program in FY 2023 and will spend nearly $1 million, although it was added after Division approval of the initial ISR Plan. The Company has proposed to install 100 new reclosers and presented that the primary driver was to target immediate reliability issues. Mr. LaBarre, however, testified that the choice of 100 was an arbitrary number and based on his determination that there are "nowhere near enough reclosers."[65] However, RI Energy's witnesses testified that they did not conduct an alternatives analysis as part of their decision. They contended that only reclosers could solve the problems identified by the Company. Furthermore, they asserted that $80,000 was not that much money per location despite requesting $17 million for the complete recloser program.[66]

After a review of the entire record during which multiple discovery responses and testimony was provided, the Commission finds that the Company failed to meet its burden of proof that this new line item was a well-developed program designed to meet an immediate or long-term reliability need and was coordinated with other reliability measures being implemented by the Company.

As noted above, a review of the Company's responses to questions about reliability does not support a finding that there is any statistical trend in SAIFI, let alone a declining trend.[67] Mr. Booth's contention that the Company is not adequately considering how to account for its various reliability enhancements is supported by the record. Taken together, trees, deteriorated equipment, and intentional outages account for 55% of all interruptions in 2021 with a rising incidence of tree-related outages. Two of these causes are addressed by the enhanced vegetation management approach and asset condition subcategories.

[65] Hr'g. Tr. at 133-34.
[66] Hr'g. Tr. at 198-99; 450-63.
[67] RI Energy's Response to RR-3 and RR-9.

As noted above in the Grid Modernization section, trees are still the leading challenge with periods of increasing SAIFI corresponding to gypsy moth tree mortality. The Company has testified that it is responding with VM enhancements to clear out the dead trees and proactively addressing the impending threats from the Emerald Ash Borer. If the Company's estimates that the enhanced vegetation management strategy will result in a 15-18% increase to reliability, that would result in SAIFI at 25% below our standard, a positive result. Even without the $9.5M budget, the system capacity and performance budget would still increase by 50% over the prior year representing a significant increase in the discretionary budget. The Commission finds that this is a sufficient system capacity and performance budget level for FY 2024.

2. CEMI-4

The Company proposed a new CEMI-4 Program (Customers Experiencing Multiple Interruptions) to address areas of poor performance. As described by the Company:

> System and Circuit Average Interruption Frequency Indices (SCAIFI) measure the experience of the average customer; however, using them exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This leads to uneven reliability performance across the distribution circuits and unhappy customers. Currently, approximately 12% (60,000) of Rhode Island Energy customers experience four or more interruptions in a rolling twelve-month period, putting Rhode Island Energy in the third quartile of performance. The CEMI-4 Program will identify and fix reliability issues for customers experiencing significantly poorer service than system or circuit averages with a goal of first quartile performance within five to ten years.[68]

In the Division's filing, Mr. Booth advised that while the Division was not recommending any adjustments to the proposal, he was concerned that this initiative is premature and not well supported by the information in the record. He also expressed concern that the proposal also overlaps with current initiatives such as the worst performing feeder

[68] Proposed FY 2024 Electric ISR Plan at Bates 106.

program and vegetation management pockets of poor performance. The CEMI-4 initiative relies on different data and approaches that similarly address localized reliability issues. He therefore, recommended that RI Energy provide additional documentation regarding how the CEMI-4 program will be implemented and tracked. Consideration should be given to the worst performing feeder program structure where the Company performs a system evaluation, determines parameters for priority circuits, develops comprehensive engineering reviews with recommended solutions, screens solutions against other planned system projects, and projects costs. He stated that the Division will expect the CEMI-4 program to be measured and validated with updated BCAs as the program progresses to determine the prudency of continuation.[69]

RI Energy responded to data requests about this initiative, including how the feeders were identified, ranked, and prioritized. At the hearing, Mr. Constable provided additional testimony about how the Company would review the feeders and choose the appropriate solutions.[70] The evidence shows that while overall reliability is within acceptable parameters, there are scattered subsets of customers who experience more than 4 interruptions per year. This can lead to customer dissatisfaction and a perception that the system is not properly maintained.

Mr. Booth, however, raised valid points and the Commission, while approving this proposal for FY 2024, directs the Company to include in its FY 2024 Electric ISR Reconciliation Filing and future ISR Plan and Reconciliation filings the following CEMI-4 a filing that contains, at a minimum, the following information:

Which feeder(s) were chosen?
What was the CEMI number?
Why was the feeder prioritized over another with a similar CEMI?

[69] Booth Test. at 61.
[70] Hr'g. Tr. at 476-88.

What was the problem identified?
What were the alternative solutions identified?
What were the costs of each solution?
Why did the Company choose the solution implemented?

If the selected solution is funded somewhere else in the ISR budget (i.e., vegetation management, a setting change, or another category), where was the cost booked and how will the benefit be tracked to the spend (in the vegetation management example, are the costs and benefits booked to vegetation management or CEMI-4)? The Company shall then track the feeder CEMI for three years and report the results as part of each ISR filing.

E. Proposed Tariff Change

RI Energy had proposed a change to the Electric ISR tariff RIPUC No. 2255 to change the FY 2024 year to a twenty-one month period and to change the definition of "Current Year" from the year ending March 31 to the year ending December 31. Consistent with the Commission's January 20, 2023 decision, the tariff change is denied.

F. Motion for Protective Treatment

RI Energy submitted a Motion for Confidential Treatment of certain information in the Area Studies provided in response to Division data request 1-20. No objection was filed. The Commission has reviewed the information and agrees that the redacted information constitutes critical energy infrastructure that is protected from disclosure under R.I. Gen. Laws § 38-2-2-(4)(B). Therefore, RI Energy's motion is granted.

G. Vegetation Management

There was no dispute between the parties about the revised 12-month Vegetation Management budget. However, the Company is making unopposed changes to its approach. Instead of simply putting all circuits on a 4-year cycle for routine pruning, RI Energy will be using data analytics to optimize its cycle pruning schedule. In addition, the Company will be examining each circuit prior to scheduling cycle pruning to determine whether the circuit requires “on-cycle outage risk reduction” pruning. According to the Company, such work would include “hazard tree removal, targeted heavy overhand removal, dying trees, structurally deficient trees, and weak wooded species removal.” This, the Company explained, should allow for all work on a circuit to be done at once, eliminating the need to send crews back out to the same circuit between scheduled cycle trimming. As a result, the budget for enhanced hazard tree management component of Vegetation Management, now called, off-cycle outage risk reduction is lower than in prior years and will target tree risks from pests such as the Emerald Ash Borer. The Company committed to continuing to track such pest related tree removal. Finally, the Company will incorporate the data analytics into the sub-transmission cycle pruning.[71]

The result of the combination of the cycle pruning with on-cycle outage risk reduction will be a reduced ability to understand the efficacy of the routine cycle trim work versus the hazard tree work. The Company has historically provided a report on the effectiveness of the enhanced hazard tree work and Commission still wants to understand the efficacy of the hazard tree work compared to the efficacy of the combined work against past performance, and to understand how much investments will be needed in each of these budget items. Therefore, within forty-five (45) days, the Company shall file a plan for how it will collect data on their vegetation management program that will allow for disaggregation of cycle pruning and enhanced hazard tree management program.

H. Capitalization Policies

Company witnesses Stephanie Briggs, Senior Manager of Revenue and Rates, Jeffrey Oliveira, Regulatory Program Specialist, Andrew Elmore, Vice President – Tax, and Natalie

[71] Proposed FY 2024 Electric ISR Plan at Bates 160-63.

Hawk, Director of tax accounting and reporting submitted testimony on the development of the revenue requirement and the impact of the transaction between PPL and National Grid. One of the topics was the Company's capitalization policy.[72] According to the testimony, while there are differences between PPL's policy and National Grid's, the Company is continuing to apply National Grid's policy in the instant filing. They explained that the capitalization policy could change during CY 2024. They proposed that any changes made during the program year would be captured in the annual ISR reconciliation.[73]

During the hearing, Ms. Briggs explained that an effect of a change to the capitalization policy would be that certain assets currently expensed would instead be capitalized. This would result in lower expenses to the Company in that year than were expected, increasing the Company's earnings in that year.[74] The Company was still evaluating the capitalization policies but had not yet performed any analysis of the effect on

[72] According to AccountingTools, Inc., a company that provides information about accounting topics to the practicing accountant:

> A capitalization policy is used by a company to set a threshold, above which qualifying expenditures are recorded as fixed assets, and below which they are charged to expense as incurred. The policy is typically set by senior management or even the board of directors.
> The threshold level set by a capitalization policy can vary considerably. A smaller business with few expenditures may be willing to accept a low capitalization threshold of just $1,000, whereas a larger business that may be overwhelmed by the recordation requirements of fixed assets may prefer a very high limit, such as $50,000. Nonprofits may prefer a low capitalization limit, so that they can keep close track of their assets. Many businesses find that a capitalization threshold of about $5,000 balances the offsetting issues of avoiding excessive record keeping and avoiding charging large items to expense as incurred.
> The capitalization policy also governs whether certain expenditures are accounted for as separate assets, or as part of a larger asset. For example, the policy could state that the roof of a building be classified separately from the rest of the structure, on the grounds that the roof may be replaced several times over the life of the building.
> Another criterion for separate classification as a fixed asset is when an item has significantly different maintenance requirements from those of nearby assets. Thus, the capitalization policy could state that a group of machines clustered on an assembly line be classified as a single asset if they share common maintenance requirements, but as separate assets if they have significantly different maintenance requirements.
> https://www.accountingtools.com/articles/capitalization-policy (last visited Nov. 7, 2023).

[73] Briggs, Oliveira, Elmore, and Hawk Test. at Bates 269-72.
[74] Hr'g. Tr. at 308-10.

expense for upcoming years under a policy change.[75] Ms. Briggs suggested that the Company would need to consider the rate impact on customers prior to implementing the policy change in the ISR prior to the next base rate case. However, she was unable to explain why this would make sense where the methodologies used to calculate the ISR revenue requirement are the same as those used in the last base rate case.[76] In addition, she was unable to determine without applying a new capitalization policy whether the impact on the ISR would be positive or negative.[77] For assets not included in the ISR, Ms. Briggs confirmed that a policy change prior to the next base rate case would impact earnings.[78]

The Commission prohibited RI Energy from reflecting in any filings, any changes to its capitalization policies that will impact rate base, operating expense, and/or the Company's earnings reports prior to the next base rate case. The Company's current revenue requirement and associated distribution rates, including ISR, were based on various policies in place in 2018. The impact on the revenue requirement and associated rates from a change to the capitalization policy is unknown. Where the ISR revenue requirement is based on the same assumptions used in setting the base distribution revenue requirement, the Company provided no persuasive evidence to apply any changes to the capitalization policy prior to the next base rate case.

Accordingly, it is hereby,

(24873) ORDERED:

1. The Narragansett Electric Company d/b/a Rhode Island Energy's FY 2024 Electric Infrastructure, Safety and Reliability Budget and Revenue Requirement, filed on December 22, 2022, is hereby rejected.

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[75] *Id*. at 310-11. In response to RR-5, the Company stated that it has not performed any studies or analysis regarding the financial impact of the potential changes in capitalization policies on expenses from now until the next rate case.
[76] *Id*. at 313-18.
[77] *Id*. at 318-21.
[78] *Id*. at 321-23.

2. The proposed tariff change reflected in Schedule PRB-1 is hereby denied.

3. The Narragansett Electric Company d/b/a Rhode Island Energy's approved FY 2024 Electric Infrastructure, Safety and Reliability revenue requirement is $55,418,057, requiring in an incremental fiscal year upward rate adjustment of $5,696,733. This will support a FY 2024 Electric ISR Plan capital budget of $112,329,000, a vegetation management budget of $13,950,000, an infrastructure and maintenance (I&M) budget of $738,000, and other expense of $425,000.

4. The Narragansett Electric Company d/b/a Rhode Island Energy's Compliance Filing filed on March 30, 2023 accurately reflects the budget levels and revenue requirement resulting from the March 29, 2023 Open Meeting decision.

5. The Narragansett Electric Company d/b/a Rhode Island Energy's Attachment 3c Supplemental – Five Year Budget with Details, marked as Exhibit 18 in this matter, serves as the document from which the adjustments were made and includes detail that will be reviewed as part of the FY 2024 Electric ISR Reconciliation filing.

6. The Narragansett Electric Company d/b/a Rhode Island Energy's Motion for Protective Treatment of its response to Division Data Request 1-20 is hereby approved because the area studies contain critical energy infrastructure and are protected from disclosure under R.I. Gen. Laws § 38-2-2-(4)(B).

7. The Narragansett Electric Company d/b/a Rhode Island Energy shall include in its FY 2024 Electric ISR Reconciliation Filing and future ISR Plan and Reconciliation filings the CEMI-4 reporting requirements included in this order.

8. The Narragansett Electric Company d/b/a Rhode Island Energy shall provide, as part of its FY 2025 filing, details on individual projects where the costs differ from budget by more than 10%, whether that difference resulted from over- or under-spending or timing. Further, in all Electric ISR quarterly reports and reconciliation filings, the Company shall provide a report and explain any budgets variance greater than 10%.

9. Contemporaneously with its FY 2025 Electric ISR Plan, The Narragansett Electric Company d/b/a Rhode Island Energy shall file a benefit analysis consistent with the Guidance Document issued Docket No. 4600A.

10. The Narragansett Electric Company d/b/a Rhode Island Energy shall not reflect in any filings, any changes to its capitalization policies that will impact rate base, operating expense, and/or the Company's earnings reports prior to the filing of its next base rate case.

11. The Narragansett Electric Company d/b/a Rhode Island Energy shall include in its review of the allocation of customer contributions to the proper cost categories

all distributed generation projects for which the customer contribution did not cover the full cost of the project; the reasons why; and the impact on rate base and the associated revenue requirement. The report shall be filed no later than August 1, 2023, with the Reconciliation of the Electric ISR filing with all necessary adjustments to any ISR revenue requirement/reconciliation explained and highlighted.

12. The Narragansett Electric Company d/b/a Rhode Island Energy shall comply with all other instructions contained in this Order.

EFFECTIVE AT WARWICK, RHODE ISLAND, ON APRIL 1, 2023, PURSUANT TO OPEN MEETING DECISIONS ON JANUARY 20, 2023, MARCH 29, 2023, AND MARCH 31, 2023. WRITTEN ORDER ISSUED DECEMBER 1, 2023.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski

Ronald T. Gerwatowski, Chairman

Abigail Anthony

Abigail Anthony, Commissioner

John C. Revens, Jr.

John C. Revens, Jr., Commissioner

Notice of Right of Appeal: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the Commission may, within 7 days from the date of the Order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or Order.

CLF 1-2

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: RHODE ISLAND ENERGY ADVANCED	**:**	
METERING FUNCTIONALITY BUSINESS CASE	**:**	**DOCKET NO. 22-49-EL**
AND COST RECOVERY PROPOSAL	**:**	

OPEN MEETING MOTIONS AND VOTES

<u>Finding of Need and Authorization for Deployment</u>

(1) Move to find that there is a need for the Company to transition its electric distribution operations from the existing AMR-based metering system to a system that utilizes advanced metering functionality (AMF). RG, AA Vote 3-0

<u>Capital Cost Recovery through the ISR</u>

(2) Move to reject the Company's proposal for a new AMF recovery factor. RG, AA Vote 3-0

(3) Move to authorize the Company to seek recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability (ISR) process as discretionary investments through the creation of a separate category with an overall multi-year CapEx cap, with the following conditions:

(a) The Company is not required to prove a need to deploy AMF for its electric distribution operations in place of the existing AMR-based metering system;

(b) The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP:Solar Marketplace, CP:Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View.

(c) The scope shall also include advancement of load disaggregation & Waveform Analytics and Grid Edge Computing that will be enabled by allowing customers to use Sense by connecting their home area network to the meter as discussed in RR-11 and shall not include acceleration of TVR.

(d) Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the ISR Fiscal Year 2025 filing shall be eligible for ISR recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior ISR filing;

(e) Recovery of the capital costs incurred for the authorized project implementation period shall be capped in the aggregate at a budget of $153,217,548 and the Company is directed to file a revised RR-9 and revised Attachment H excel spreadsheet to reflect $0.00 for the items removed and to show the O&M related to acceleration of Sense.

(f) Regarding the Special Sector Deferrals identified in the Amended Settlement Agreement and listed in Attachment PUC 7-13, lines 3 and 4, the ongoing annual net cumulative accrual shall only be used to offset the annual AMF revenue requirement that is eligible for ISR cost recovery each year.

RG, AA Vote 3-0

(4) Move that the Meter Data Management System (MDMS) costs shall not be eligible for rate base recovery; provided, however, 44% of the capital costs associated with the work performed by Landis+Gyr which the Company allocated to AMF shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return. RG, AA Vote 3-0

(5) When the Company submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed. RG, JR Vote 3-0

(6) Move to direct the Company to file an ISR Addendum to encompass the findings herein for further review by the Commission. The addendum shall include a proposal to recover the revenue requirement associated with the eligible AMF CapEx spending to be appropriately allocated to each rate class and recovered through a fixed charge embedded in the applicable customer charge for each rate class for further review by the Commission. RG, AA Vote 3-0

Treatment of O&M Expenses Prior to Next Rate Case

(7) Move that any operation and maintenance (O&M) expenses (i) relating to the AMF project implementation period or (ii) relating to AMF "run-the-business" costs, which expenses are incurred during the period prior to new base distribution rates going into effect from the next base distribution rate case may not be deferred or recovered in any new rates. RG, AA, Vote 3-0

(8) Move that effective on the date of this decision through the effective date of the Company's next base distribution rates, the Company may net O&M expenses that relate to the AMF scope as defined above against the accumulating regulatory liability relating to certain residual revenue requirement items identified in Docket 4770 and enumerated in PUC 7-13, RR-7, and/or RR-13. To the extent that such O&M expenses during that period are less than the total accumulated regulatory liability as of the date that new base distribution rates go into effect, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission. RG, JR Vote 3-0

(9) Move to direct the Company to file a schedule that updates Attachment PUC 7-13 with actuals through Rate Year Ending August 31, 2023, includes the AMF-related portion of all other grid mod costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1, and provides a forecast through the anticipated effective date of the next base distribution rate case. In addition, the Company shall provide the cumulative balances as of August 31, 2023 in a separate section. RG, JR Vote 3-0

(10) Move to direct the Company to update the revised schedule that was just voted on with each annual ISR filing and reconciliation filing and also include a schedule which shows the O&M expenses that have been netted against the rate level credit balance. RG, JR Vote 3-0

Accountability Requirements

(11) Move that the effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in prior motions today. AA, JR Vote 3-0

(12) Move to adopt the following requirements the Company must comply with under the authorization to advance its AMF investment plan:

<u>ADMS Integration</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the meter data is integrated into the ADMS. The company should report on the number of meters installed, time to install the meters, integration with ADMS, and any outliers. Prior to commencing meter installation the company needs to provide the PUC and DPUC definitions of the geographic deployment areas.

<u>Voltage Notification</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the company has configured real time alerts for over/under voltage and is using the ADMS ping to investigate voltage issue.

<u>Outage Notification</u>: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for outage notification.

<u>Remote Connect/Disconnect</u>: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for remote connect, disconnect, service activation, and account transfers.

<u>Theft Detection</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for theft detection.

<u>Customer Portal</u>: Company will maintain a customer portal. At a minimum, there should be no discontinuity of customers' ability to access account information and pay bills online.

Load Disaggregation: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that customers are able to access disaggregated load data. Within 12 months of the conclusion of the deployment period, the company will report on customer access and utilization of disaggregated load data.
AA, JR Vote 3-0

(13) Move that within two months of the start of meter installation, the Company must file plans that address Green Button Connect, Home Area Network, and Grid Edge Computing, as described below. The company may consult with any stakeholder deemed necessary, but the plan must be filed by the company and will be reviewed by the Commission in a contested proceeding.

Green Button Connect: Within two months of the start of meter installation, the company must file a Green Button Connect plan that addresses the following:

a. For every customer specific item on the bill, whether that same information should be provided through GBC;
b. At a minimum, the company should plan to provide the same data fields and historical information as offered or planned to be offered to its customers in Pennsylvania and Kentucky.
c. For each of the items in (a), whether the underlying customer-specific data (e.g. interval meter reads, voltage) should be provided through GBC;
d. To the extent historical data is provided for (a) and (b), provide the extent of that data set. Specifically address whether it is appropriate to provide 36 months of electric consumption.
e. Whether (a), (b), and (c) should be provided for gas.
f. Whether any additional customer specific data beyond (a) and (b) should be provided through GBC (e.g. disaggregated load data).
g. Timeline for GBC certification and version of certification.

Home Area Network: Within two months of the start of meter installation, the company must file a Home Area Network plan that addresses the following:

h. Version of bring-your-own-device that will be offered to customers, and requirements, if any, on those devices;
i. Access to usage and disaggregation insights;
j. Whether any charges apply to customers or device-makers;
k. Technical standards for local devices;
l. Terms and conditions on direct upload of usage data and disaggregation insights.

Grid Edge Computing: Within two months of the start of meter installation, the company must file a Grid Edge Computing plan that presents a framework or terms and conditions for each issue identified in Mission:data Coalition's Post-Hearing Statement section 3, parts (a) through (f).
AA, JR Vote 3-0

(14) Move to direct Rhode Island Energy to engage with the DPUC to negotiate the details and implementation of the following service quality mechanisms and file an updated Service Quality Plan for Commission review and approval in Docket 3628 within 3 months. Other parties will be able to intervene in Docket 3628.

1. Meter reading & billing:
    a. Monthly percent of meters read is an existing reporting requirement in the service quality plan in Docket 3628.
    b. The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period.
    c. The service quality mechanism should establish a threshold that represents appropriate performance (e.g. the average of the past three years).
    d. The maximum penalty will be imposed for performance 2.5 standard deviations below the threshold.
    e. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum penalty was determined.
    f. The design may or may not be linear, and it may include a dead band.
    g. Following the meter installation period, the Company and Division may propose an update to this service quality mechanism in Docket 3628.
2. Faster outage notification:
    a. The company will be subject to a one-time faster outage notification service quality mechanism 12 months after full project implementation.
    b. The service quality mechanism should establish a baseline for outage notification.
    c. The maximum penalty will be imposed if evidence shows that the company is notified of outages 0 minutes faster than the baseline.
    d. No penalty will be imposed if evidence shows that the company is notified of outages 22 minutes faster than the baseline.
    e. The metric may be an annual average over all customers or explain why a different metric was chosen.
    f. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.
    g. The mechanism may or may not be linear. Intervals, bins, and dead-bands may be considered.
    h. The mechanism may (but is not required to) include a shared savings mechanism for evidence that that the company is notified of outages more than 23 minutes faster than the baseline.
3. Network speed:
    a. The company will be subject to a one-time or continuous network speed service quality mechanism 12 months after full project implementation.
    b. The service quality mechanism should establish a measurement of network speed. The measurement should capture the speed of information from the meter to the MDMS and back to the customer portal or explain why a different measurement

was chosen. The service quality mechanism should establish the time period and scope of the measurement.

   c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.
   d. The company and parties should propose the maximum penalty and threshold. Intervals, bins, and dead bands may be considered.

4. Trouble, Non-Outage
   a. Trouble, non-outage calls are an existing reporting requirement in the service quality plan in Docket 3628.
   b. Within twelve months after meter installation starts, the company will be subject to a service quality mechanism for trouble, non-outage calls.
   c. The service quality adjustment should impose scaled penalties for increased trouble, non-outage calls, compared to a baseline. The metric, baseline, minimum, and maximum should be defined and justified.
   d. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.
5. Customer satisfaction
   a. Customer satisfaction (customer contact survey) is an existing service quality mechanism in the service quality plan in Docket 3628.
   b. Within six months after meter installation starts, the company will be subject to an updated customer contact standard that reflects the company's expectations of higher customer satisfaction. Updates may include, but not be limited to, increasing the minimum percent satisfied threshold, increasing the value of the penalty, and narrowing the dead band.
   c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.

   AA, JR Vote 3-0

<u>Conclusory Motions</u>

(15) The Commission authorizes the Company to deploy an AMF-based metering system for the electric distribution business subject to the conditions already voted on. RG, AA Vote 3-0

(16) The Company is not required to commence the authorized project implementation. The decision to move forward under the terms of the Commission's authorization rests within the management discretion of the Company; provided, however, if such project implementation is commenced, the conditions set forth by the Commission in the decisions today shall apply. RG, AA Vote 3-0.

CLF 1-3

JOINT PRE-FILED SUPPLEMENTAL DIRECT TESTIMONY

OF

KATHY CASTRO,

RYAN CONSTABLE,

AND

CARRIE GILL

August 11, 2023

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I. Introduction

Kathy Castro

Q. Ms. Castro, please state your name and business address.

A. My name is Kathy Castro. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am employed by Rhode Island Energy as the Director of Asset Management and Engineering. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 30, 2022.

Ryan Constable

Q. Mr. Constable, please state your name and business address.

A. My name is Ryan Constable. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am employed by Rhode Island Energy as an Engineering Manager in the Distribution Planning and Asset Management Department. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted joint pre-filed direct testimony in this proceeding on December 30, 2022.

<u>Carrie Gill</u>

Q. Dr. Gill, please state your name and business address.

A. My name is Carrie Gill. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am employed by Rhode Island Energy as Senior Manager of Electric Regulatory Strategy within the External Affairs team. In this role, I am responsible for general regulatory matters, policy development, and filings, including providing strategic support to inform business decisions that advance safe, reliable, affordable electricity distribution.

Q. Please describe your educational background and professional experience.

A. I received a doctorate in environmental and natural resource economics from the University of Rhode Island in 2017, master's degrees in business administration and oceanography from the University of Rhode Island in 2010, and a bachelor's of science in physics and mathematics from Loyola University, Maryland, in 2007.

Prior to my role with Rhode Island Energy, I served multiple positions with the Rhode Island Office of Energy Resources from 2017 to 2022, culminating my tenure as chief economic and policy analyst. In that role, I provided strategic oversight of clean energy and climate policies and programs for the State of Rhode Island. Prior to 2017, I held various research and teaching assistantships within University of Rhode Island (2012-2017); provided independent consulting to a solar thermal developer in Washington, DC (2012); served as a Knauss Fellow within the U.S. Department of Energy's Wind and Water Power Program (2011-2012); and supported the Coastal Resources Center with research on coastal community climate adaption (2010).

Q. Have you previously submitted testimony in this proceeding?

A. No, I have not previously submitted testimony in this proceeding. However, I have submitted testimony for Rhode Island Energy in Docket 22-39-REG. I have also testified on several occasions during my tenure with the Rhode Island Office of Energy Resources.

Q. Are you sponsoring any attachments within this supplemental testimony?

A. Yes, we are sponsoring Attachment 1, which is a Grid Modernization Plan ("GMP") Analysis Supplement and introduced in further detail within our supplemental testimony.

Q. Why is Rhode Island Energy filing this supplemental testimony?

A. Rhode Island Energy ("the Company") is filing this supplemental testimony to address potential concerns and questions that may still be outstanding since it filed the GMP in December 2022 and the Prehearing Conference that was held in May 2023.

Q. What are the concerns and questions the Company intends to address via this supplemental testimony?

A. The Company addresses the following topics in this testimony:

- Purpose of the GMP
- Scope of the GMP docket
- GMP Analysis
- Timing of when to begin investments
- Pace of investments
- Alternatives to the term "foundational investments"
- Cost recovery
- Intersection of GMP and the Infrastructure, Safety, and Reliability ("ISR") Plan

- Relationship to Advanced Metering Functionality ("AMF")

Q. How is this supplemental testimony organized?

A. This supplemental testimony is organized into sections corresponding to the list of topics in the question above. Section I is the introduction. Section II discusses the purpose of the GMP. Section III discusses the scope of the GMP docket. Section IV discusses the GMP Analysis.[1] Section V discusses the timing of when investments may begin. Section VI discusses the pace of investments. Section VII discusses the term "foundational investments." Section VIII discusses cost recovery. Section IX discusses the intersection of the GMP and the ISR. Section X discusses the GMP's relationship to AMF. Section XI concludes this supplemental testimony.

In each section, the Company describes its intent in addressing each topic, attempts to address potential outstanding questions and concerns via incremental information or reframing of prior information, and cross-references readers to specific sections of the GMP that provide more detail. At times, the Company may provide responses that reframe information presented previously – this reframing is not intended to be a contradiction, but rather an alternative way of describing consistent sentiments in hopes that the reframing will be more easily understandable and provide further clarity.

[1] The Company uses the term "GMP Analysis" to refer to the distribution study and the benefit-cost assessment.

II. Purpose of the GMP

Q. Please describe the Company's intent in addressing this topic.

A. In this section of testimony, the Company attempts to clarify its perspective on the purpose of the GMP and the value the Company gained by developing the GMP.

Q. How does the Company view the purpose of the GMP?

A. The Company views the GMP as the validation for evolving its *investment strategy*, which will result in different *investment proposals*, such as in future ISR Plans.[2]

In the GMP, the Company evaluates the effectiveness of two investment strategy alternatives for addressing electric distribution system issues today and under increasing penetration of distributed energy resources ("DER").[3] These two investment strategy alternatives are: (i) the Company's status quo investment strategy of traditional investments only (e.g. reconductoring, upgrading transformers, non-wires solutions, etc.;

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[2] The Company is intentionally using the term "investment strategy" here to refer to the overarching strategy for how to address electric distribution system issues. In contrast to an "investment strategy," the specific justifications for the individual investment proposals – solutions to specific electric distribution system issues – will be included when the Company proposes each specific investment and will include the electric distribution system issue and the proposed solution.

[3] With increasing penetration of DER and policy signals that seem to encourage further penetration, the Company considered the present (beginning as early as 2017 when developing its rate case in Docket 4770/4780) to be a timely opportunity to revisit its investment strategy to ensure the strategy results in reasonable and prudent investment proposals to resolve electric distribution system issues.

referred to herein as the "traditional investment strategy"); and (ii) the Company's alternative strategy of a smaller extent of traditional investments integrated with grid modernization investments (e.g. adding information technology solutions and communicating sensors in the field, etc.; referred to herein as the "grid modernization investment strategy").[4]

For any *single, isolated* electric distribution system issue, traditional investments often represent the best-fit, least-cost alternative. This is because integrating any level of grid modernization investment necessitates large up-front costs, for example, for the information technology required to ingest, analyze, and communicate with field equipment.

However, it was not certain before now whether a strategy of traditional investments only remains best-fit, least-cost for a *portfolio*[5] of electric distribution system issues. Further, increasing penetration of DER presented a complicating factor that warranted appropriate modeling and analysis. The Company conducted such an analysis when developing the GMP.

[4] This "traditional investment strategy" is described in Book 2 Section 5.2 as the "No Grid Mod Modernization Alternative." This "grid modernization investment strategy" is described in Book 2 Section 5.2 as the "Grid Modernization Alternative."

[5] The Company uses the term "portfolio" to mean a set or multiple (in contrast to one).

In the GMP, the Company describes the analysis it performed to understand which investment strategy alternative is best-fit, least-cost for a portfolio of electric distribution system issues in light of increasing penetration of DER. The Company finds that a strategy of traditional investments integrated with grid modernization investments – the grid modernization investment strategy – is actually best-fit, least-cost for a portfolio of electric distribution system issues with the current penetration of DER seen in localized areas of Rhode Island.[6]

Q. What is the main takeaway of the GMP?

A. The GMP shows that an investment strategy of traditional investments integrated with grid modernization investments – a grid modernization investment strategy – is best-fit, least-cost for a portfolio of electric distribution system issues in Rhode Island. These electric distribution system issues include issues the Company is seeing now, such as interconnection and operational flexibility of DER, maintaining reliability, expanding volt/var optimization to save energy, and the continuous effort to improve worker and public safety. Therefore, the insights from the GMP suggest the Company should shift away from a traditional investment strategy to a strategy of traditional investments integrated with grid modernization investments – a grid modernization investment

[6] The Company addresses potential concerns and questions about the analysis itself, the timing to begin investments, and the pace of investments in Sections IV, V, and VI of this supplemental testimony.

strategy – to resolve electric distribution system issues in future investment proposals, such as in the annual ISR.

Solutions derived from a grid modernization investment strategy are further described within the GMP on an illustrative basis. In completing its GMP Analysis, the Company finds that one such solution – enabling demand-side or customer-side control of electricity use – stands out in importance for achieving safe, reliable, affordable electric service.

Q. What value did the Company get from developing the GMP?

A. The Company recognized the high-level difference between the two investment strategies and benefits of each but did not have the necessary analysis completed to evaluate one against the other prior to developing the GMP.

Through the development of the GMP, the Company developed more advanced analysis tools and methods to conduct the review and determine the appropriate alternative. Prior to developing the GMP, the existing data sets, tools, and methods were not adequate to quantitatively analyze tradeoffs between investment strategies to resolve electric distribution system issues in future states of the world (in relation to increasing penetration of DER). Specifically, the Company improved its prior static analysis to be more dynamic and granular (e.g., modeling all circuits using 8,760 hourly models to identify electric distribution system issues and how specific solution sets alleviate those issues).

In working through the GMP Analysis, the Company was able to better understand the implications of two investment strategy alternatives, including their implications for safety, affordability, and reliability.

Q. How does the Company intend for the GMP to be used?

A. The Company intends for the GMP to be used as a complementary document, akin to how an area study tests alternatives and guides multi-year investments as proposed through formal filings, such as, but not limited to, the ISR.

These documents (e.g., area studies) are not filed for regulatory review of any single element (though there is extensive engagement with the Division of Public Utilities and Carriers, referred to herein as the "Division"). In the same manner, the Company lays out its decision-making framework in the GMP to center the conversation around those objectives. Akin to area studies, the Company will rely on the findings of the GMP (with its analysis driven by the same area study planning criteria) to guide refined and targeted investment proposals through appropriate dockets, such as investment proposals that are reasonably needed to maintain safe and reliable distribution service over the short- and long-term in each annual ISR Plan.

There is not an exact parallel between the GMP and area studies; rather, the Company draws conceptual similarities within this response to aid understanding of the Company's intent for how the GMP should be used. The difference between the GMP and area studies is that the GMP validates an investment strategy whereas the area studies provide specific investment solutions.

Q. From the Company's perspective, what would go beyond the intended use of the GMP?

A. The Company does *not* intend for the GMP to be used as a static forecast of electric distribution system issues. Although the analysis employs an upper bound of DER penetration, the Company does not view this upper bound as representing a forecasted state of the world.[7]

Similarly, the Company does *not* intend for the GMP to be used as a static investment plan. Although the investments described within the GMP are those that result from the specific modeling it conducted, the Company will propose only those investments that are needed, when they are needed, within the appropriate regulatory filing. In this manner, the GMP is not a static investment plan but a breathable, flexible document

[7] The Company addresses potential outstanding questions and concerns about its analysis and its use for this upper bound scenario Section IV of this supplemental testimony.

describing an investment strategy that will be deployed with on- and off-ramps to guide future targeted investment proposals.[8]

Q. What value does the Company get from having the GMP?

A. The Company developed the GMP – including its extensive analysis and stakeholder engagement – for multiple reasons:

1. To understand the tradeoffs of different investment strategies;
2. To provide transparency into the Company's decision-making process;
3. To work through scale, sequencing, and pace of investments, and associated implications; and
4. To develop quantitative analysis methodologies.

The Company views the GMP as providing the validation for an investment strategy that integrates traditional investments with grid modernization investments – a grid modernization investment strategy. Having a GMP documented and in the public record fosters transparency about and builds understanding of benefits and costs of alternative investment strategies and provides insight into the Company's long-term investment strategy to supplement each investment proposal (i.e., the annual ISR Plan).

[8] The Company addresses potential outstanding questions and concerns about future investment proposals in Sections VIII and IX of this supplemental testimony.

Q. Why did the Company file the GMP?

A. The Company filed the GMP to satisfy the Company's obligation under the Amended Settlement Agreement ("ASA") approved by the Rhode Island Public Utilities Commission ("PUC") in Docket Nos. 4770/4780, Order No. 23823.

Q. Does the Company view the GMP as evidence?

A. The Company is not requesting approval of the contents of the GMP or preauthorization of its investment strategy such that the Company can rely on that approval in subsequent proceedings. Approval of proposed investments will go through the appropriate evidentiary hearings in the relevant dockets.

The Company does, however, intend to use the GMP as evidence in those future dockets to demonstrate that deriving solutions to electric distribution system issues from a grid modernization investment strategy results in solutions that are best-fit, least-cost relative to the traditional investment strategy for a portfolio of electric distribution system issues. In this sense, the Company relies on the findings of the GMP as internal evidence to support business functions – the GMP is the Company's due diligence in examining alternative investment strategies – and may refer to the GMP as evidence in future regulatory proceedings to support and justify its proposed investments, which the Commission may weigh as it deems appropriate.

Q. What is the difference between the GMP filed in Docket No. 22-56-EL and the GMP as contemplated in Docket 4770/4780?

A. Although the GMP as filed in Docket 22-56-EL in 2022 meets the requirements of the GMP as defined in Docket No. 4770/4780, Order No. 23823, and the ASA, the Company has evolved how it intends to use the GMP it filed in Docket No. 22-56-EL in 2022.[9] The Company understands its original grid modernization vision in Docket No. 4780 in 2018, and the resulting GMP as contemplated in Order No. 23823 and the ASA, to be more akin to a multi-year investment plan, albeit with clear on- and off-ramps. However, the Company now emphasizes that the Company, its customers, the PUC, and parties to the ASA are best served by a more breathable and flexible document that provides insights into the best investment strategy under whatever penetration of DER materializes.[10]

Q. How does the Company envision the PUC and the Division could use the GMP?

A. The Company intends that the GMP Analysis provides the PUC and other parties, including the Division, with insights into the increasing complexities of the electric system due to dynamic and distributed technologies, associated electric distribution system issues, potential solution alternatives, and linkages between these. With these

[9] The Company acknowledges an iteration of the GMP was filed in Docket No. 5114 on January 21, 2021, and withdrawn on September 12, 2022.

[10] Book 2 Section 1.2 contains additional detail regarding the history of Docket 4770/4780 and the ASA requirements.

insights, the PUC, Division, and other parties could use the GMP to understand the Company's validation for proposing solutions to resolve electric distribution system issues that are derived from a grid modernization investment strategy. The Company describes such solutions in the GMP and discusses how these solutions interact to optimize net value for customers.

III. Scope of the GMP Docket

Q. Please describe the Company's intent in addressing this topic.

A. The Company's intent in addressing this topic is to help inform the scope of the GMP docket by discussing the Company's perspective on a possible approach.

Q. How does the Company think about the relationship between the scope of the docket and the purpose of the GMP?

A. The scope of the docket should stem directly from the purpose of the GMP. In other words, the docket should assess whether the GMP has met its purpose.

Q. What is the Company's recommendation for the scope of this docket?

A. The Company views the purpose of the GMP as the validation for evolving its investment strategy, which will result in different investment proposals, such as in future ISR Plans. The Company's recommended scope of this docket therefore allows for meaningful discussion about the contents of the GMP but stops short of requesting approval of specific investments or their cost recovery.

The Company requests that the PUC "issue an order affirming that the Company has complied with its obligation to file a GMP that meets the requirements of the ASA".[11] Order No. 23823 in Docket No. 4770/4780 references "twelve minimum requirements for inclusion in the Grid Modernization Plan" (Order No. 23823 Bates Page 23) that were then incorporated into the ASA (see Section 15 of the ASA). The Company considers that a finding that the GMP complies with the ASA is, therefore, also a finding that the GMP complies with Order No. 23823, thereby satisfying the Company's obligation under Docket No. 4770/4780.

Assessing whether the GMP meets the ASA requirements aligns with the Company's objective to foster transparency about how it is evolving its investment strategy. The twelve requirements are:

"The GMP will take into account the time period for any proposed AMF implementation, and it will include, at a minimum:

[11] The Company states its request for ruling affirming that it has complied with its obligation to file a GMP that meets the requirements of the ASA in Book 2, Section 9, Bates Page 209.

1. Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document;
2. Explanation of the role of currently active programs;
3. Investments and technology deployments planned through the end of any proposed AMF implementation;
4. Functionalities to achieve those objectives;
5. Review of options for candidate technologies to deliver those functionalities;
6. Transparent, updated benefit cost analyses that fully incorporate the Docket No. 4600 framework;
7. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;
8. A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term;
9. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;
10. Explanation of congruency with grid modernization activities in New York and Massachusetts;
11. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and

12. A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation." [Order No. 23823, Appendix A, Bates Page 51]

The Company acknowledges that the PUC may vet the GMP's compliance with the ASA through data requests, technical sessions, or hearings, and may include a request for parties to the ASA to intervene, provide testimony, or submit public comment. In offering this recommendation for scope, the Company intends to offer a flexible framework from which the PUC can right-size the depth and breadth of the GMP docket.

Q. Why does the Company not request approval of the contents of the GMP or the specific investments it contains?

A. The Company does not request approval of the GMP itself or the specific investments it contains for several reasons.

First, the GMP validates an investment strategy, which is a fundamental business strategy and is within the purview of the Company to make. A request for approval of the GMP itself would imply a request for approval of a business decision, which would not be an appropriate request to the PUC.

Second, an evidentiary hearing inclusive of detailed engineering review of specific investments within the GMP may be duplicative and inappropriate. The investments – scale, timing, pace – arising from the scenario modeling conducted in the GMP are illustrative to support the Company's analysis of tradeoffs between the baseline traditional investment strategy and the alternative grid modernization investment strategy. The Company is not proposing any specific investments or cost recovery within the GMP; the Company will submit refined investment proposals in targeted areas to address specific electric distribution system issues through appropriate regulatory avenues for further review and oversight.[12] These refined investment proposals will be different from those discussed within the GMP because they will be right-sized and right-timed based on actual electric distribution system issues as they arise.

Q. Is the Company amenable to a larger scope than what it recommends?

A. Yes. While the Company recommends the PUC align the scope of the GMP docket to understand the justification for the Company shifting from a traditional investment strategy to a grid modernization investment strategy, the Company will be a cooperative partner in the docket regardless of how the PUC defines the scope.

[12]The Company states that it is not seeking approval of any particular investments or seeking any cost recovery as part of this GMP in Book 2, Section 1.1, Bates Page 6.

IV. GMP Analysis

Q. What is the Company's intent in providing supplemental testimony regarding the GMP Analysis?

A. The Company recognizes that the PUC and parties have outstanding questions about the GMP Analysis. Throughout this testimony, the Company uses the term "GMP Analysis" to refer to both the distribution study and the benefit-cost assessment. Outstanding questions include clarifications on the methodology and the reasoning for the methodology, linkages between the electrical analysis and the benefit-cost analysis, and the relation of findings to the purpose of the GMP. In this section, the Company attempts to directly answer some of these outstanding questions.

Q. Please summarize the key points of clarification the Company would like to address.

A. To evaluate the effectiveness of switching from a traditional investment only strategy to a grid modernization investment strategy, the Company attempted to analyze tradeoffs in the most conservative manner – meaning the benefits were modeled to be lower bounds and the costs were modeled to be upper bounds, rendering the most conservative benefit-cost ratio.

The GMP Analysis employs a scenario under which maximum investments are required under a grid modernization investment strategy. This scenario is not a forecast. The Company employed this scenario as an upper bound on electric distribution system issues as a proxy for an upper bound on investments – and costs – to address those issues. In conducting the benefit-cost assessment, the Company generally used lower bounds on estimates of each benefit category. Despite the lower bound of benefits and the upper bound of costs, the Company finds a benefit-cost ratio of evolving to a grid modernization investment strategy that is persistently greater than 1.0 across sensitivity analyses.

The GMP Analysis includes three benchmarks (2030, 2040, and 2050) and annual modeling, which implicitly allows the Company to glean insights about the tradeoffs between investment strategies at lower penetrations of DER. Therefore, even though the Company employs an upper bound and long-term 2050 scenario in its GMP Analysis, the GMP Analysis still provides insights for short-term investment.

The GMP Analysis identifies technological solutions to electric distribution system issues that may be derived from a grid modernization investment strategy, but the Company does not consider these solutions to constitute an investment plan.

Q. Regarding benefits, in your prior response, you stated that the Company generally used lower bounds on estimates of each benefit category when conducting the benefit-cost assessment. Can you substantiate this?

A. Yes, the Company provides examples in Table 1, below. The Company intentionally shows a subset of benefits based on the benefit categories associated with the largest valuation. For more information on all benefits within the benefit-cost assessment, please see Section 8 of the GMP, Book 2 in Docket No. 22-56-EL.

Table 1: The GMP Analysis employs a conservative estimate for benefits – examples from a subset of benefits.

Benefit-Cost Category	**Estimation Methodology in GMP Analysis**	**How Estimate in GMP Analysis is Conservative**
Avoided Infrastructure Costs	The Company first identified infrastructure costs for solutions to electric distribution system issues arising in 2050 derived from (i) the traditional investment strategy and (ii) the grid modernization investment strategy. The Company used the difference in costs between (i) and (ii) to represent avoided infrastructure.	Although the Company used the full cost of solutions derived from the grid modernization investment strategy for the cost valuation, the Company only used 55% of the avoided infrastructure costs in its valuation (8% assigned to 2027-2030, 47% assigned to 2031-2042, 45% assigned to 2043-2050 but not included in the BCA).
Reduced DER Curtailment	The Company assumed no benefits from reduced curtailment in 2023-2029; a downscaled-but-positive benefit in 2031-2042, and zero benefit in 2043-2050.	The downscaled-but-positive benefit assigned to 2031-2042 reduced the total benefit valuation by 22%. The realization of zero valuation assigned to 2043-2050 is highly unlikely.
CCO/CVR Benefits	The Company estimated benefits using findings from a third-party vendor evaluation of the Company's pilot.	The evaluation found 1.3% - 3.5% energy savings; the Company assumed 2% energy savings in its valuation (0.7% higher than lower bound, 1.5% lower than upper bound).
Reduced Outage Frequency	The Company estimated benefits using five-year historical data.	The Company reduced the number of successful operations by 25%. DOE reports benefits ranging 11% - 49%; the Company is using 26% (15% higher than lower bound, 23% lower than upper bound).
Utility O&M Savings	The Company assumed a 2% growth rate of O&M expenses when calculating savings.	The Company's actual growth rate for O&M expenses is 3%, so 2% is a conservative assumption.

Q. Regarding costs, the Company says that the GMP Analysis employs an upper bound scenario under which maximum investments are required under a grid modernization investment strategy. How did the Company develop this upper bound scenario and why isn't it a forecast?

A. The Company developed this upper bound scenario with the objective of seeing the most dynamic changes from historical conditions on the electric distribution system. These changes arise from adoption of technologies that (i) increase demand, (ii) increase two-way power flow, and (iii) decrease predictability of load curves. These three characteristics would lead to the most difficult-to-plan-for and most difficult-to-operate-through conditions. Technologies that contribute to these three conditions include distributed generation, renewable energy, electric vehicle charging, and electric heating and cooling. These technologies are also those technologies that are likely to increase in adoption as driven by public policies and the market signals they send. One example of a public policy and its signal to markets is the 2022 Renewable Energy Standard, which signals to the renewable energy market that there may be longer-term value streams from development and continuation of state-driven incentives for in-state development. Another example is the State's recent adoption of the Advanced Clean Cars II regulation, which phases out sales of new light-duty vehicles with internal combustion engines in the coming decade and therefore likely sends market signals encouraging electric vehicle markets in the State (and further supports those markets through state-level and federal-level incentives for electric vehicles).

The Company specifically considered the 2021 Act on Climate in developing its upper bound scenario in the GMP Analysis because the 2021 Act on Climate sets greenhouse gas emissions reductions mandates that are likely to provide at least some level of encouragement to adopt the range of technologies that result in the most dynamic changes from historical conditions on the electric distribution system. Specifically, the Company assumed the State meets these climate mandates through near-complete electrification of thermal and transportation sectors and fully in-state development of renewable energy resources. The Company understands that the 2021 Act on Climate does not require in-state renewable energy resources and that electrification is one pathway of several to reduce greenhouse gas emissions. The Company employed this scenario – which is not a forecast – to model a state of the world with the most electric distribution system issues, and therefore the highest cost of investments to resolve those issues.

Q. How does employing this upper bound scenario in the GMP Analysis provide insight into decisions today?

A. The GMP Analysis methodology would provide insight into decisions today if (i) the GMP Analysis methodology includes modeling of a short-term scenario and (ii) the short-term scenario modeled is similar to a short-term forecast. The Company contends that its GMP Analysis methodology meets both of these criteria.

First, although the GMP Analysis considers electric distribution system issues that emerge from an upper bound scenario analysis through 2050, the GMP Analysis also models benefits and costs in benchmark years 2030 and 2040, developed from an underlying annual model. The underlying annual model was not included in the GMP, but the Company has included this data in this supplemental testimony as Attachment 1 with the intent of adding depth of transparency and, therefore, aiding in understanding the analysis and resulting insights. The GMP Analysis methodology does include modeling of a short-term scenario and therefore meets criteria (i).

Second, the short-term scenario modeled is nearly identical to the contemporaneous electric peak forecast and therefore satisfies criteria (ii).[13] Table 2, below, shows the modeled uptake of DER in the GMP Analysis relative to the Company's contemporaneous electric peak forecast for solar PV, electric vehicles, electric heat pumps, and energy efficiency.[14] This table shows that the GMP Analysis used short-term

[13]Electric Peak (MW) Forecast. Published November 2021. https://systemdataportal.nationalgrid.com/RI/documents/RI_PEAK_2022_Report.pdf

[14]Other DER included in the GMP Analysis include land-based wind, offshore wind, demand response, and energy storage. Land-based wind and offshore wind are omitted from the electric peak forecast because of their negligible impact on summer peak load and are, therefore, not included in Figure 2. Omission of land-based wind and offshore wind from this comparison does not have any material bearing on the argument that the model used in the GMP Analysis is similar in the short-term to expected forecast. Although demand response and energy storage are elements of the electric peak forecast, they are not assumed in the same manner in the GMP Analysis. In contrast, the Company considered levels of demand response and energy storage as endogenous to the model used in the GMP forecast; resultant levels of demand response and energy storage from the GMP Analysis are greater than those levels in the electric peak forecast.

(through 2036) assumptions that were identical to the forecast at that time, with the sole exception of installed nameplate capacity of solar PV in years 2030 through 2036. The Company further explains how the PUC and parties may consider this difference in their interpretation of findings throughout this section of the supplemental testimony (see also specifically Figure 2g.i and 2g.ii and the Company's associated discussion in Attachment 1).

Also of note: the contemporaneous electric peak forecast did not account for market signals from the 2022 Renewable Energy Standard, the 2021 Act on Climate, the Inflation Reduction Act, the National Electric Vehicle Infrastructure Act, or other recent policies that are likely to incrementally encourage market growth and penetration of DER. Therefore, one may also argue that the Company's electric peak forecast may represent a somewhat lower bound future scenario.

Notwithstanding, given how closely the model in the GMP Analysis aligns with the Company's electric peak forecast, the model in the GMP Analysis does indeed represent plausible expectations for the short-term.

Satisfaction of these criteria prompt the Company to consider the insights of its GMP Analysis – notably the benefits of evolving to a grid modernization investment strategy – as being applicable to immediate decision-making.

Table 2. GMP Analysis assumptions and Electric Peak Forecast through 2036

	PV (MW)			**EV (number vehicles)**			**EH (number systems)**			**EE (MW)**		
Year	**GMP Analysis**	**Forecast**	**Delta**	**GMP Analysis**	**Forecast**	**Delta**	**GMP Analysis**	**Forecast**	**Delta**	**GMP Analysis**	**Forecast**	**Delta**
2022	498	498	0	7039	7039	0	6052	6052	0	370	370	0
2023	601	601	0	10605	10605	0	8752	8752	0	387	387	0
2024	704	704	0	15288	15288	0	12052	12052	0	404	404	0
2025	808	808	0	21305	21305	0	15952	15952	0	422	422	0
2026	901	901	0	29494	29494	0	20652	20652	0	440	440	0
2027	984	984	0	39962	39962	0	26352	26352	0	458	458	0
2028	1060	1060	0	52855	52855	0	33152	33152	0	475	475	0
2029	1128	1128	0	68623	68623	0	41352	41352	0	491	491	0
2030	1791	1189	602	87321	87321	0	51152	51152	0	507	507	0
2031	1981	1244	737	109241	109241	0	60462	60462	0	522	522	0
2032	2171	1293	878	133813	133813	0	69307	69307	0	536	536	0
2033	2361	1337	1024	161266	161266	0	77709	77709	0	549	549	0
2034	2551	1377	1174	190458	190458	0	85691	85691	0	562	562	0
2035	2741	1414	1327	222046	222046	0	93274	93274	0	574	574	0
2036	2931	1446	1485	254981	254981	0	100478	100478	0	586	586	0

Notes: PV corresponds to cumulative installed nameplate capacity for solar photovoltaic systems (MW). EV corresponds to cumulative number of electric vehicles, inclusive of light-duty and heavier-duty vehicles. EH corresponds to cumulative number of electric heat pumps. EE corresponds to energy savings in MW. All Forecast figures correspond to the base forecast, not the low or high scenario forecasts. Delta is the difference between assumed adoption in the GMP Analysis and the forecasted adoption in the electric peak forecast. A delta of 0 indicates adoption values are identical between the GMP Analysis and electric peak forecast.

Q. How does this scenario modeling provide insight into which investment strategy is most cost-effective?

A. The model that the Company employs in its GMP Analysis is granular by year; the benefit-cost assessment in the GMP Analysis includes inputs and outputs on an annual basis from 2023-2042 (the 20-year term used). The Company uses this annual level analysis to gain insight into which investment strategy is most cost-effective. In Attachment 1, the Company provides supplemental analysis at an annual granularity to support the insights discussed within this supplemental testimony.

Q. Please elaborate on how this annual analysis included in Attachment 1 provides insight.

A. In developing the GMP, the Company sought to understand whether (and the extent to which) a grid modernization investment strategy is more cost-effective than a traditional investment strategy for resolving a portfolio of electric distribution system issues. These electric distribution system issues arise from adoption of DER spurred by a broader policy shift to decarbonization (see pg. 23:2 herein). The Company anticipates substantial and significant change through 2050, corresponding to the State's mandate to reach net-zero greenhouse gas emissions. Although there likely will continue to be changes in technology adoption and use patterns post-2050, the Company anticipates these changes to be less substantial than changes anticipated over the next three decades.

Therefore, the Company can consider an equivalent corollary of its research question: "at what point in time does a grid modernization investment strategy break even with a traditional investment strategy?"[15] If the Company finds that a grid modernization investment strategy is likely to become more cost-effective than a traditional investment strategy in the nearer-term, then the Company can be reasonably certain that transitioning to a grid modernization investment strategy will prove beneficial for its customers. If, however, the Company finds that a grid modernization investment strategy is unlikely to become more cost-effective than a traditional investment strategy prior to 2050, then the Company should continue with a traditional investment strategy as cumulative costs of grid modernization would likely not exceed the benefits.

In Attachment 1, the Company presents its findings regarding benefits and costs from the GMP Analysis on an annual basis.

Q. What is the Company's main finding?

A. The Company finds that cumulative benefits begin to outweigh cumulative costs within 10 years, which is within the portion of modeling that is (nearly) identical to the Company's peak electric forecast.

[15]Equivalently: If the Company were to evolve from a traditional investment strategy to a grid modernization investment strategy today, at what point in time would the cumulative benefits of the grid modernization investment strategy equal (begin to exceed) the cumulative costs?

Using the upper bound scenario model presented in the GMP and assuming a prompt transition in investment strategy, the Company estimates that evolving to a grid modernization investment strategy will be cost-beneficial relative to a traditional investment strategy by 2030 (equivalently: after eight years of employing the grid modernization investment strategy).

This finding has two corollaries. First, examining the relative effectiveness of the grid modernization investment strategy and the traditional investment strategy over a time period less than eight years, all else equal, omits critical costs and benefits and thereby biases the results and masks the cost-beneficial investment strategy.

Second, the cumulative benefits begin to outweigh the cumulative costs in 2030, which is within the near-term period where modeling is nearly identical to the electric peak forecast. This insight is critical because it suggests the grid modernization investment scenario is cost-beneficial relative to the traditional investment scenario given *solely* high-probability short-term adoption of DER.[16] In contrast, if the point of intersection were found to be in later years (e.g. 2040s), then the timing of intersection (and whether intersection occurs prior to 2050) may be contingent on adoption of DER in the upper

[16]The exception is the modeled installed nameplate PV in the year 2030. This exception is discussed herein and addressed within Attachment 1. Findings are relatively insensitive to adjusting the installed nameplate solar PV within the GMP Analysis to match the electric peak forecast, and the Company reaches the same conclusion about the effectiveness of the grid modernization investment strategy.

bound scenario (post-2036 forecast alignment). That the intersection occurs in the near term is stronger evidence of the effectiveness of the grid modernization investment strategy relative to the traditional investment strategy than if the intersection were found to occur closer to 2050.

Q. Does the Company explore whether this finding is robust to different assumptions?

A. Yes. The Company also conducted several sensitivity analyses (presented in detail in Attachment 1) to understand the extent to which the timing of this breakeven point is sensitive to various assumptions about costs and benefits. The Company found that the timing of the breakeven point is relatively insensitive to assumptions about benefits, including the inclusion and monetization of societal benefits, the inclusion and value of direct customer benefits, the inclusion and value of benefits linked to reduced outages and AMF, the inclusion of costs and benefits related to fiber, and the downscaling of benefits to align with solar PV adoption in the Company's electric peak forecast; in all cases the breakeven point falls between 2030 and 2034.[17] In other words, the finding that the grid modernization investment strategy is cost-beneficial relative to a traditional

[17]The Company additionally constructed a conservative-and-unlikely scenario where zero value was assigned to societal and direct customer benefits, AMF-related benefits, reduced outage related benefits, and benefits downscaled to align with solar PV adoption in the Company's electric peak forecast. This scenario is conservative because it assigns zero value to several benefits that the Company expects will have positive value. This scenario is unlikely because it may be interpreted as a scenario in which these benefits do not occur at all, which is contrary to the Company's expectations. In this conservative-and-unlikely scenario, the breakeven point is 2038. Therefore, if investments were to occur as modeled within the GMP Analysis, the Company is confident that the breakeven point would likely occur prior to 2038. The Company provides more detail and discussion regarding the sensitivity analyses in Attachment 1 and regarding actual investment deployment schedule in Section VI.

investment strategy for a portfolio of solutions to electric distribution system issues is robust.

Q. How is this finding sensitive to assumptions about costs, when to begin investing, and how to pace investments?

A. The upper bound scenario used in the GMP assumes the maximum number of electric distribution system issues and therefore the maximum anticipated number of scalable grid modernization technologies (e.g., advanced reclosers). If a smaller amount of DER are adopted than is modeled, cumulative costs would decrease. If cumulative costs are lower, and benefits stay the same, then the breakeven point would occur sooner. If cumulative costs are lower and benefits are lower commensurately, then the breakeven point would not change.

If the timing of when to begin investing in solutions derived from a grid modernization investment strategy were delayed, then the costs and benefits, and the breakeven point would shift into the future. If this delay were to be sufficiently long, then there may be too many lost opportunities for a grid modernization investment strategy to provide cost-beneficial value. This underscores the Company's shift to a grid modernization investment strategy promptly.

If the investments in solutions derived from a grid modernization investment strategy were to be paced out, then costs and benefits would both accrue more slowly, thereby pushing the breakeven point further into the future. Furthermore, slower pacing adds some uncertainty to costs due to inflation, which may put upward pressure on costs and further delay the breakeven point.[18] As with the timing of when to begin investments, if investments were to be paced out sufficiently slowly, then there may be too many lost opportunities for a grid modernization investment strategy to provide cost-beneficial value. This underscores the Company's proposed swift implementation of a grid modernization investment strategy.

V. <u>Timing of When to Begin Investments</u>

Q. This next section of testimony continues the line of questioning of insights gained from the GMP Analysis, specifically insights as related to the timing of when to begin investments. Please describe the Company's intent in addressing this topic.

A. The purpose of the GMP is to evaluate the effectiveness of evolving to a grid modernization investment *strategy*. Through its GMP Analysis, the Company finds that evolving its investment strategy from traditional investments only to a grid modernization investment strategy is cost-beneficial for a portfolio of solutions to resolve electric distribution system issues. The breakeven point will occur within some definite interval

[18] There may be other cost pressures as well that have either similar or opposite impacts (e.g., deferral value of delayed investment).

of time following the beginning of investments. In this section of testimony, the Company aims to clarify how the GMP Analysis provides insight into the tradeoffs associated with when the Company begins to implement a grid modernization investment strategy.

Q. The Company has discussed the immediacy of issues and urgency of grid modernization since filing its rate case in 2018, and then again in its grid modernization plan filings in 2021 and most recently in 2022 in this docket; however, the electric system still seems to be operating reliably. Why should the PUC and parties consider shifting to a grid modernization investment strategy to be urgent?

A. The Company has been addressing electric distribution system issues with solutions derived from a traditional investment strategy and the employment of operational procedures which, in certain cases, limit the Company's flexibility in operating the electric distribution system and addressing ancillary issues. For example, relative to solutions derived from a grid modernization investment strategy, solutions derived from a traditional investment strategy have less ability to allow for reconfiguration of the electric distribution system and limited ability to dynamically leverage DER. The GMP Analysis shows that, although these traditional investment strategy solutions may address each electric distribution system issue that has arisen, solutions derived from a grid modernization investment strategy would have contributed to a more cost-effective and operationally flexible electric distribution system. Furthermore, solutions derived from a traditional investment strategy will be less technically viable in future years than solutions derived from a grid modernization investment strategy.

Q. Provide an example of work that would have been different if the Company had derived solutions using a grid modernization investment strategy instead of the traditional investment strategy.

A. Solutions derived from a grid modernization investment strategy could have assisted the Nasonville restoration in many ways. The Company's response to Division 1-33 issued on November 4, 2022, in the Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan, Docket No. 22-53-EL, describes the issues and how such solutions could have mitigated the issues. The Nasonville event alone does not justify an evolution from a traditional investment strategy to a grid modernization investment strategy. Rather, the Nasonville event provides a recent case of how the Company's investment strategy manifests itself and the comparative effects of solutions derived from either investment strategy.

Q. If the Company believes the grid modernization investment strategy will be more cost-effective for a portfolio of solutions addressing electric distribution system issues, why doesn't the Company implement those solutions as normal course of business?

A. The Company is implementing certain solutions derived from a grid modernization investment strategy as normal course of business to the extent it is able to do so. For example, the Company will be setting up ADMS Basic as a result of the Acquisition,[19] and the Company is beginning to invest in advanced reclosers that will be able to integrate with the ADMS system.

The Company's implementation of a grid modernization investment strategy, however, is limited by its ability to recover costs for the limited set of upfront, fixed-cost investments required by a grid modernization investment strategy. This question of ability to recover costs underlies the pace of implementing the grid modernization investment strategy, rather than the question of when to begin implementing a grid modernization investment strategy.[20]

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[19]The term "Acquisition" refers to PPL Rhode Island Holdings, LLC's, a wholly owned indirect subsidiary of PPL Corporation, acquisition of 100% of the outstanding shares of common stock of The Narragansett Electric Company from National Grid USA. ADMS Basic is further explained in the Executive Summary and Section 1 of the GMP.

[20] *See* Section VIII of this testimony on Cost Recovery for additional discussion.

Q. What insight does the Company glean from the GMP Analysis regarding when to begin implementing a grid modernization investment strategy?

A. The GMP Analysis demonstrates that evolving from a traditional investment strategy to a grid modernization investment strategy is cost-effective. If the timing of when to begin investing in solutions derived from a grid modernization investment strategy were delayed, then the costs and benefits, and the breakeven point, would shift into the future. If this delay were to be sufficiently long, then there may be too many lost opportunities for a grid modernization investment strategy to provide cost-beneficial value. This underscores the Company's shift to a grid modernization investment strategy.

Q. The Company has previously tied the effectiveness of a grid modernization investment strategy to claims regarding reliability, but these claims have been disputed. If the PUC and parties are not convinced that reliability is declining, then are the findings of the GMP Analysis moot?

A. No, the findings are not moot even if reliability trends are disputed. The Company supplemented its narrative in the GMP with discussion of declining reliability and the effect reliability has on customer satisfaction. While the Company stands by its claims, the findings of the GMP Analysis are independent of claims regarding reliability. Reliability appears in the GMP Analysis as a benefit associated with solutions to electric distribution system issues derived from a grid modernization investment strategy. This benefit is not relational; the magnitude of the benefit is independent of current, past, and future levels of reliability, and reliability trends. Furthermore, the Company's supplemental analysis included in Attachment 1 demonstrates that a grid modernization investment strategy is cost-effective relative to a traditional investment strategy even when omitting benefits of reduced outages (or, equivalently, assigning those benefits zero value). Therefore, the Company arrives at the same conclusion – that it is cost-effective to evolve to a grid modernization investment strategy – regardless of whether reliability has decreased, increased, or stayed the same in recent years.

VI. Pace of Investments

Q. Describe the Company's intent in addressing this topic.

A. In this section of testimony, the Company aims to alleviate any confusion over how it is proposing to pace solutions derived from a grid modernization investment strategy, how those investments will be proposed, when they will be proposed, where they will be proposed, and whether cost recovery could be delayed, by providing clarity about the Company's strategy to right-size, right-time, and right-locate solutions, and tradeoffs with various investment schedules. Importantly, the Company emphasizes that the solutions derived from a grid modernization investment strategy in the upper bound scenario in the GMP Analysis are *not* intended to be an investment plan nor are they intended to be an all-or-nothing investment proposal.

Q. If this GMP is not an investment plan, how will the Company determine the pacing of investing in solutions derived from a grid modernization investment strategy?

A. First, the Company's objective in proposing the quickest pace possible (e.g. immediate and swift switch to a grid modernization investment strategy) is to realize the most cost-savings and most benefits over the coming decades. However, the Company also understands that the benefit-cost assessment is only one of many potential inputs into decision making and that the Company's recommended pace may not be the preferred pace of the PUC and other parties. In this manner, there is not a black-and-white, all-or-nothing solution, but rather a calculus among shades of gray.

Second, the Company will right-size, right-time, and right-locate solutions derived from a grid modernization investment strategy through its annual planning process with appropriate regulatory oversight, such as in each annual ISR Plan. Some solutions derived from a grid modernization investment strategy rely on a limited set of upfront fixed costs for investments like information technology. This limited set of up-front fixed costs is indeed why a traditional investment strategy may appear to be best-fit, least-cost to resolve any single immediate-term electric distribution system issue. However, the GMP Analysis shows that a short-term perspective masks the cost-effectiveness of the grid modernization investment strategy. Some investments illustrated in the GMP will be required in order for other solutions to be technically viable (e.g., ADMS is required to achieve the full functionality of some operational technology solutions). Other investments, like advanced reclosers, can be scaled. In saying that the Company will right-size, right-time, and right-locate these solutions, the Company intends to convey that there is (1) flexibility in pace, (2) on- and off-ramps for investment, and (3) opportunity for due diligence in regulatory oversight.

Q. Provide a specific example of what the PUC and parties may see as a "right-sized, right-timed, right-located" solution. In this example, describe the flexibility, on- and off-ramps, and opportunity for due diligence.

A. One example of how the PUC and parties will see the Company propose a "right-sized, right-timed, right-located" solution derived from a grid modernization investment strategy is with advanced reclosers. The Company will employ a strategy that considers factors like circuit average interruption frequency and duration, line exposure, and existing sectionalization in prioritizing locations for advanced reclosers, and factors like supply chain lead times and construction bundling opportunities in responding to cost and time constraints. The Company will apply such a strategy on an annual basis to propose a right-sized, right-timed, right-located recloser program in each ISR, with due diligence from collaboration with the Division prior to filing and with appropriate regulatory oversight from the PUC and intervenors within each ISR docket.

In this example, the Company has the flexibility to propose or not propose advanced reclosers as a solution to immediate-term electric distribution system issues. The on-ramp for deploying advanced reclosers are the electric distribution system issues for which an advanced recloser would be a solution (i.e., without an issue present and defensible, there is no on-ramp for which to propose an advanced recloser). The off-ramp is the scalable nature of advanced reclosers (i.e., installing one hundred advanced reclosers does not bind the Company or regulators to installing ten more). The opportunity for due diligence is the Company's internal annual planning process and the associated annual regulatory oversight process conducted in alignment with ISR statutory and regulatory standards.

Q. Please discuss the Company's intent with including an execution schedule with its GMP?

A. First, the Company would like to clarify what is meant by offering an execution schedule. Because the GMP is not an investment proposal, the Company would like to avoid any inadvertent signal that the Company will propose the entirety of solutions derived from grid modernization investments illustrated in the GMP Analysis, or at the pace illustrated within the GMP.

The purpose of providing an execution schedule is to demonstrate the pacing with which such solutions may be phased in and to aid in internal project planning for multi-year projects. Although the GMP Analysis indicates the effectiveness of an immediate evolution to a grid modernization investment strategy, the pacing of these solutions can be flexible and should not be pre-determined prior to identifying and assessing each electric distribution system issue as it arises.

Furthermore, the Company recognizes that, while a prompt transition to a grid modernization investment strategy would offer the largest degree of cost-effectiveness soonest, doing so may not be preferable considering cost impacts to customers. Therefore, the Company discerns that a thoughtful approach to pacing that considers the broader economic landscape and competing policy priorities is advantageous. The Company contends that its execution strategy – proposing right-sized, right-timed, right-located solutions through appropriate cost recovery channels – provides for the nuance and flexibility needed to weigh tradeoffs in pacing.

VII. <u>Alternatives to the term "Foundational Investments"</u>

Q. Describe the Company's intent in addressing this topic.

A. The term "foundational investments" has been used since 2018, but its meaning has evolved, thus making the true intent of the term unclear. In this section of testimony, the Company avoids rehashing prior interpretations and instead offers a different distinction for types of investments to facilitate discussion of the issues at hand.

Q. What further distinction may help facilitate conversation about the GMP?

A. The Company proposes to distinguish between investments with fixed costs (e.g., ADMS) and investments that are scalable (e.g., advanced reclosers). By distinguishing between these two types of investments, the PUC and parties can more clearly discuss how the size of the portfolio of electric distribution system issues affects the benefit-cost assessment of alternative investment strategies.

Specifically, for a single electric distribution system issue or a sufficiently small portfolio of electric distribution system issues, the fixed costs of underlying investments required for solutions derived from a grid modernization investment strategy will render an unfavorable benefit-cost assessment relative to a traditional investment strategy. However, the incremental benefits at the relatively low incremental cost of scalable solutions derived from a grid modernization investment strategy led to the insight that a grid modernization strategy is cost-effective relative to a traditional investment strategy.

Another distinction is the difference between an investment that is a pre-requisite and an investment that is not a pre-requisite. For example, ADMS Basic is a pre-requisite for FLISR. This distinction may be helpful in understanding the dynamics within the benefit-cost assessment because a pre-requisite investment may have a relatively high cost with low benefit on its own but enable scalable solutions that have low cost and high benefit when considered together.

VIII. <u>Cost Recovery</u>

Q. Describe the Company's intent in addressing this topic.

A. The Company's intent with this section of testimony is to address possible outstanding questions about how the Company will request cost recovery for solutions derived from a grid modernization investment strategy by describing available pathways for cost recovery and elaborating on its strategy for how it will request cost recovery in the future.

Q. How is the Company thinking about cost recovery considering the GMP's purpose?

A. The purpose of the GMP is to validate an evolution of investment strategy from traditional investments only to a grid modernization investment strategy. This investment strategy will be used as the underlying framework from which the Company derives solutions to electric distribution system issues. In other words, the grid modernization investment strategy will become, over time, the Company's new business-as-usual strategy.

As such, the Company will apply this investment strategy across all its business functions, and solutions stemming from it will be proposed for cost recovery in the venue in which cost recovery is most appropriate in alignment with statutory and regulatory standards. Any proposal for cost recovery will be subject to appropriate regulatory oversight and review.

For example, the Company will apply the grid modernization investment strategy to electric distribution system issues identified in area studies. These solutions may be proposed for cost recovery through the annual ISR to the extent such investments and spending are reasonably needed to maintain safe and reliable distribution service over the short and long term pursuant to R.I. Gen. Laws § 39-1-27.7.1(d). Another possible cost recovery mechanism is through base distribution rates in accordance with Order No. 23823 and the ASA. All cost recovery proposals will be subject to appropriate regulatory oversight and review.

Q. Why is proceeding with all investments and recovering costs through base rates during the next rate case not appropriate?

A. First, the shift from a traditional investment strategy, known today as "business-as-usual" to a grid modernization investment strategy requires significant upfront costs, which would be impractical for the Company to undertake absent assurances for cost recovery.

Second, the appropriateness of any cost recovery mechanism depends on the investment for which costs are recovered, understanding of which customers cause the costs and which customers benefit from the investment, and all applicable statutory and regulatory standards.

There may be some investments that are appropriate for the Company to make and then request cost recovery through a subsequent base distribution rate case. The Company should not, however, be required to defer recovery to a subsequent base distribution rate case in circumstances where there is an alternate regulatory or statutory mechanism that would allow for cost recovery.

For example, for investments and spending that are reasonably needed to maintain safe and reliable distribution service over the short and long term, per R.I. Gen. Laws §39-1-27.7.1(d), the Company should be able to obtain cost recovery through its ISR Plan.

Q. How is the Company considering cost causation when determining the most appropriate cost recovery mechanism?

A. The Company understands that cost causation is an important driver in fair cost recovery. From the Company's perspective, it is getting increasingly difficult to pinpoint cost causers, and the solutions – especially solutions derived from a grid modernization investment strategy – increasingly provide benefits to customers beyond the cost causers. For example, while distributed generation interconnection may necessitate a mainline recloser (e.g., to protect the electric distribution system via adjustments to impedance), that mainline recloser also provides the additional value of enhancing reliability through sectionalization, which benefits all customers.

Another example: 3VO is often required for distributed generation interconnection, but the proliferation of distributed generation precludes the Company from pinpointing a single cost causer. 3VO is an approved program through the ISR that recovers cost from all customers in accordance with the Allocated Cost of Service Study underlying the ISR Tariff, rather than cost recovery from distributed generation customers solely.

The Company will continue to consider cost causation as a driver of whatever cost recovery mechanism(s) it proposes but does not see a determination of cost causation as a threshold question of the GMP docket.

IX. Intersection of the GMP and the ISR Plan

Q. What is the Company's intent in addressing this topic?

A. The Company's intent is to address possible concerns about duplicating administratively burdensome reviews between the GMP docket and future ISR dockets, and the sequencing of review of the GMP relative to the ISR for maximum insight.

Q. How does the Company envision the PUC and parties review the GMP and ISR to avoid duplicative review?

A. The Company envisions the review of the GMP to be distinct and different from the review of the ISR. The Company describes its vision for the review of the GMP in detail in Section III.

Q. Does the Company see the need for the GMP docket to be complete prior to evaluation of any grid modernization solutions proposed for cost recovery through the ISR?

A. No. From the Company's perspective, there is no need for the GMP docket to be complete prior to evaluating solutions derived from a grid modernization investment strategy within the ISR (or any other docket). In each ISR Plan, the Company will identify electric distribution system issues with the appropriate justification (identified using accepted planning criteria, polices, and other considerations to prioritize issues to be addressed). The Company will right-size, right-time, and right-locate its solutions to those electric distribution system issues, with due diligence and collaboration with the Division prior to submission to the PUC. This right-sizing, right-timing, and right-locating will depend in part on factors related to the electric distribution system issues at hand (e.g., only proposing solutions to electric distribution system issues that are immediate) and in part on factors related to pacing of investments (see Section VI of this testimony for more information). The Company will describe how the solutions meet the standard of review for the ISR (i.e., that the investments and spending are reasonably needed to maintain safe and reliable distribution service over the short- and long-term). In other words, the Company intends to include the justification necessary for any solutions proposed through the ISR Plan within the ISR Plan itself, and this justification should stand on its own outside of the GMP.

X. Relationship to AMF

Q. Please describe the Company's intent in addressing this topic.

A. In this section of supplemental testimony, the Company aims to clarify how it considers the relationship between evolving to a grid modernization investment strategy and deploying advanced metering.

Q. Where has the Company previously described this relationship?

A. The Company previously described this relationship in its responses to PUC 1-1, PUC 1-2, Division 5-7 and Division 5-4 in Docket No. 22-53-EL.

Q. Is AMF a prerequisite to transitioning to a grid modernization investment strategy? Is transitioning to a grid modernization investment strategy a prerequisite to AMF?

A. AMF is not a prerequisite to the Company evolving to a grid modernization investment strategy.[21] AMF is a complementary investment proposal aligned with, but not required by or enabled by, an underlying grid modernization investment strategy.

[21] Additionally, the Company's sensitivity analyses discussed in Section IV and presented in Attachment 1 demonstrate the effectiveness of the grid modernization investment strategy is robust to removal of benefits linked with deployment of AMF.

Evolving to a grid modernization investment strategy is not a prerequisite to deploying AMF. The business case for AMF stands on its own, as demonstrated in Docket No. 22-49-EL.

Although AMF and investments stemming from a grid modernization investment strategy are independent of one another, they are related in the sense that they enhance each other. For example, many, but not all, grid modernization investments are capable of leveraging the increased quantity, quality, and frequency of data made available by AMF meters to deliver increased functionalities and benefits. Similarly, AMF meters are capable of interacting with some of the grid modernization investments to better reduce outage response through automated sectionalization.

Nevertheless, they are not prerequisites for one another because both AMF and grid modernization investments deliver functionalities and benefits on their own, without the need to leverage or interact with one another.

XI. Conclusion

Q. Does this conclude your testimony?

A. Yes, thank you.

CLF 1-4

CLF 1-1

Request:

On pages 47-48 of the ISR plan, the Company asserts that it "…has assessed that approval of this ISR Plan promotes the Act on Climate mandates by preparing the electric distribution grid to integrate greater renewable energy generation as discussed in detail through the Grid Modernization Plan."

a. What method of assessment was used to determine that the proposed investments in this ISR plan promotes the Act on Climate mandates?

b. Does "promote," as used in this assertion, mean that it furthers the ability of the State to achieve the mandates contained in the Act on Climate?

c. If not, what does the Company mean by "promote"?

Response:

a. The Company makes this assertion based on its technical-economic assessment contained within the Grid Modernization Plan (see Docket No. 22-56-EL, both the filed Plan and the supplemental testimony) and a qualitative assessment based on our customers' growing reliance on the electric distribution system as the State decarbonizes.

   The Company's analysis that is the basis of its Grid Modernization Plan comprehensively compares long-term costs of the electric distribution system under a range of plausible future states of the world in terms of electrification and penetration of distributed energy resources. The Company compares costs using a traditional investment strategy relative to a grid modernization investment strategy and finds that a grid modernization investment strategy is likely to result in lower costs for customers. The investments the Company makes in alignment with a grid modernization investment strategy include reclosers, capacitors, and advanced relays, which promote data, sensing, and control on the distribution system, as well as communication investments such as the fiber study and potential future fiber projects.

   Qualitatively, general project work within the ISR strengthens the electric distribution system by maintaining and/or improving safety and reliability, both of which are needed throughout the State's decarbonization now and into the future. These investments often have related benefits that can allow for higher penetration of distributed energy resources and electrification. For example, a conversion project from a 4 kilovolt system to a 15

CLF 1-1, page 2

kilovolt system will provide additional generation hosting capacity in addition to the projects primary goals of addressing asset issues, load capacity, or reliability.

b. The Company intended the use of the word "promote" to be interpreted as "supports" or "helps". By way of example, failure to maintain the safety and reliability of the electric distribution system may discourage electrification and slow decarbonization. Similarly, if maintaining the electric distribution system is done through a more costly portfolio of investments, then electric rates will be higher and will send price signals that are contradictory to the strategy of electrifying as a way to decarbonize. The work the Company has proposed in this ISR is aligned with the objective of decarbonization because the work maintains and/or improves safety and reliability in a more affordable manner than other potential investment strategies.

c. Please see the response to part b.

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CLF 1-2

Request:

Referencing the same section identified in 1-1 above, the Company appears to indicate that the only portion of the ISR that intersects with the Act on Climate is its facilitation of greater integration of renewable energy generation.

a. In the Company's opinion, is this an accurate assessment of the impact that this ISR proposal will have on the State's ability to achieve the Act on Climate mandates?

b. If not, what other provisions of the ISR are likely to impact whether the State will meet these mandates?

c. What does the Company mean by "integrate" with respect to renewable energy generation?

Response:

a. Yes, the statement that "this ISR Plan promotes[1] the Act on Climate mandates by preparing the electric distribution grid to integrate greater renewable energy generation" is an accurate assessment of an impact this ISR proposal will have on the State's ability to achieve the Act on Climate mandates, but it does not reflect all the impacts the proposed investments can have on achieving those mandates. The Company also recognizes that the linkages between the proposed investments and decarbonization is broader than renewable energy generation. In addition to the positive impacts of the proposed investments on renewable energy generation, these investments may also serve to promote electrification and other distributed energy resources. This statement is not intended to comment on the State's ability to achieve the Act on Climate mandates; achievement is dependent on a number of factors outside of the Company's control.

b. The investments within the ISR plan that have functionality that ties to the Grid Modernization Plan will also facilitate integration of electric vehicles and charging infrastructure, heating electrification, and energy storage. The general investments within the ISR plan often provide load hosting capacity in addition to generation hosting capacity. (Please see the Company's response to CLF 1-1 part a).

c. The Company intends "integrate" to mean lowered or moderated interconnection costs and an ability to establish operating parameters to maximize renewable generation in high penetration areas.

[1] Please see the Company's response to CLF 1-1 for further clarification of the term "promotes."