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. 23-48-EL**
PLAN FY 2025 PROPOSAL	**:**

REPORT AND ORDER

I. Overview

On December 21, 2023, 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 the period April 1, 2024 through March 31, 2025 (ISR Fiscal Year).[1,2] RI Energy indicated that the Division of Public Utilities and Carriers (Division) was generally in agreement with the proposed plan.[3,4]

Following discovery, testimony from the Division, the filing of position statements from the Attorney General and Conservation Law Foundation (CLF), additional revised budget filings, and two and a half days of hearings, on March 26, 2024, the Commission ultimately reduced the capital budget by $9,346,000.[5] The adjustment resulted in an approved revenue requirement of $54,861,882, representing a downward adjustment in revenue

[1] The FY 2025 Electric ISR Plan and all of the documents referenced herein can be found on the Commission's website at: https://ripuc.ri.gov/Docket-23-48-EL.
[2] In Order No. 24873 at 6-10 (In re: The Narragansett Electric Company d/b/a Rhode Island Energy FY 2024 Electric ISR Plan), the Commission addressed the issue of the timing of the fiscal year for ISR Plans in the context of the Company's calendar year fiscal year which was different from National Grid's. The Commission found that it is appropriate to continue using the fiscal year April 1 through the following March 31 and that there was no statutory requirement to realign the ISR Fiscal Year with the Company's actual fiscal year.
[3] Filing Letter at 1 (Dec. 21, 2023).
[4] The RI Attorney General, Office of Energy Resources (OER), and Conservation Law Foundation intervened in this matter, but did not present witnesses.
[5] Compare Attachment 3 of Initial Filing with Attachment 3 in Compliance Filing at page 4 of 4.

requirement from the prior fiscal year of $556,176.[6] This will support a FY 2025 Electric ISR Plan capital investment budget of $131,569,000, a vegetation management budget of $13,075,000, an infrastructure and maintenance (I&M) budget of $700,000, and VVO/CVR O&M budget of $365,000.[7]

The Commission also adopted a new budget framework that sets an overall soft budget cap, a hard cap on separately tracked multi-year projects, and vegetation management and I&M budget caps. As part of its decision, the Commission allowed $200,000 for a fiber study to be tracked separately.

II. Rhode Island Energy's Filing

A. Budget

In its initial filing, the Company submitted an Electric ISR Plan covering the 12-month period April 1, 2024, through March 31, 2025. The initial proposed revenue requirement for the period was $54,197,806 to support a capital budget of $140,915,000 plus Operations & Maintenance (O&M) expense of $14,140,000 for vegetation management; Inspection & Maintenance (I&M); and Volt/Var Optimization and Conservation Voltage Reduction Expansion (VVO/CVR).[8]

The Company included six spending categories within the capital investment budget: to meet statutory and regulatory requirements applicable to the electric system (Customer Request/Public Requirement);[9] to repair failed or damaged equipment (Damage Failure);[10] to address load constraints caused by growing/shifting customer demands on the system (System

[6] Compliance Filing, Section 5:Attachment 1(C).
[7] *Id*.
[8] Section 5:Attachment 1 at 1; Section 2: Electric Capital Plan (Initial Filing, Bates page 79).
[9] FY 2025 Electric ISR Plan at Bates page 60.
[10] *Id*. at 61.

Capacity and Performance);[11] to replace assets due to condition issues (Asset Condition);[12] and a new line item for Advanced Metering Functionality (AMF) spending.[13] The AMF spending budget and associated rules were addressed by the Commission in Docket No. 22-49-EL (In re: Rhode Island Energy Advanced Metering Functionality Business Plan and Cost Recovery Proposal).[14] An overall AMF spending budget cap was approved, and the annual revenue requirement was allowed to be recovered through the ISR Factor. The initial budget in FY 2025 was $51,725,000 and included a revenue requirement associated with that spending. However, as a result of a delay in the execution of the project, the FY 2025 budget was subsequently revised to $48,192,000.[15]

B. Development of the FY 2025 Revenue Requirement

Stephanie Briggs, Senior Manager of Rates, Jeffery D. Oliveira, Regulatory Programs Specialist, and Natalie Hawk, Director of tax accounting and reporting filed testimony to explain how the proposed FY 2025 revenue requirement was developed. The revenue requirement consists of the Vegetation Management, O&M, and VVO/CVR activities; capital investment (plant in service), a property tax recovery adjustment; and a tax hold harmless adjustment required as part of the approval of the acquisition of Rhode Island Energy by PPL Corporation.[16] The proposed revenue requirement for FY 2025 was $54,197,806.

During the course of the proceeding, the Company identified an error in its calculation of the hold harmless provision. The result of correcting the error was an increase to the FY

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[11] *Id*. at 68.
[12] *Id*. at 63.
[13] *Id*. at 79.
[14] https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-11/2249-PUC-OM-V0TES_9-27-23.pdf.
[15] Compliance Filing at Attachment 3, page 4 of 4.
[16] Initial Filing at Bates page 310.

2025 total revenue requirement will by $1,250,081.[17] Thus, the Company's proposed FY 2025 revenue requirement was revised to $55,447,887.

The Company originally calculated a $4,722,076 revenue requirement related to AMF, to account for placing AMF assets into service in FY 2025. However, per the AMF decision referenced above, there would have been no rate impact due to certain offsets already included in the Company's rates.[18] Subsequently, because of the delay in the AMF rollout, the Company withdrew its request for a revenue requirement in FY 2025 related to AMF.[19]

C. Development of the ISR Factor

In written testimony, Tyler Shields, 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 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

[17] RI Energy Response to RR-6.
[18] FY 2025 Electric ISR Plan at Bates page 316.
[19] Compliance Filing at Attachment 3, page 4 of 4; Hr'g. Tr. at 29-30 (Mar. 13, 2024).

classes.[20] 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.[21]

III. Approved FY 2024 Electric ISR Budget and Revenue Requirement

Following evidentiary hearings conducted over two and a half days during which the Commission heard testimony from twelve Company witnesses,[22] John Bell, Chief Accountant to the Division, and Gregory Booth, consultant to the Division, the Commission considered the evidence at an Open Meeting held on March 26, 2024. 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 $54,861,882, representing a downward adjustment in revenue requirement from the prior fiscal year of $556,156. This will support a FY 2025 Electric ISR Plan capital budget of $131,569,000, a vegetation management budget of $13,075,000, an infrastructure and maintenance (I&M) budget of $700,000, and a VVO/CVR budget of $365,000.[23]

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[20] Shields Test. at Bates 321-27; 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 326-27.

[21] Shields Test. at 324, 327.

[22] Philip Walnock, PPL Director of Product Portfolio and Field Operations; Parker Capwell, RI Energy Manager of Advanced Meter Functionality; John Schwartz, Manager of Asset Accounting; Stephanie Briggs, RI Energy Senior Manager of Revenue and Rates; Ryan Constable, RI Energy Manager of Distribution Planning and Asset Management; Kathy Castro, RI Energy Vice-President of Electric Distribution Operations; Eric Wiesner, RI Energy Director of Asset Management and Engineering; Christopher Rooney, RI Energy Manager of Forestry; Daniel Glenning, RI Energy Director of Project and Construction Management Natalie Hawk, PPL Tax Director; Jeffrey Oliveira, Regulatory Program Specialist; and Tyler Shields, Rates and Regulatory Specialist.

[23] 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).

A. ISR Budget Framework

During its review of last year's FY 2024 Electric ISR filing and FY 2023 Electric ISR Reconciliation, the Commission expressed concern with the level of expected growth in the ISR budgets and related growth in the revenue requirement translating to increased ratepayer expense.[24] As part of its decision on the FY 2025 Electric ISR Plan, the Commission adopted a new budget framework to attempt to hold spending close to approved budgets, and where there is significant overspend, better balance the sharing of risk between the Company and its ratepayers.

Throughout the proceedings the Commission discussed the Company's required burden of proof and the ISR exception to traditional ratemaking principles. The Commission made it clear that it is the Company and not the Commission that ultimately bears responsibility to provide safe and reliable service. However, the special rate treatment for rate recovery under the ISR construct which eliminates any lag in cost recovery is only contemplated by statute "for the anticipated capital investments and other spending pursuant to the annual pre-approved budget as developed in accordance with subsection (d) of this section."[25] Section (d) outlines the budget development and approval process. This means that the Company is only entitled to cost recovery under this statutory mechanism for those investments contemplated and approved within a spending year budget.[26] It does not relieve

[24] Docket No. 22-53-EL (FY 2024 Electric ISR Plan) Hr'g. Tr. at 220-222 (Mar. 8, 2023); Docket No. 22-53-EL (FY 2024 Electric ISR Plan) Hr'g. Tr at 336-43 (Mar. 9, 2023); Docket No. 5209 (FY 2023 Electric ISR Reconciliation) Hr'g Tr. at 66-67 (Sept. 14, 2023).

[25] R.I. Gen. Laws § 39-1-27.7.1(c)(2).

[26] In the FY 2023 Electric ISR Reconciliation, a question arose about "whether the Company was attempting to recover costs related to commencement of a program that was ultimately not approved by the Commission." The Company and Division ultimately entered into a settlement on the issue whereby the Company agreed to remove certain plant additions related to spending that was not presented in the FY 2023 Electric ISR Plan nor approved in the FY 2024 Electric ISR Plan and the Division agreed to review it in a future filing. (Order No. 25131 at 8-9 (Aug. 5, 2024)). The Commission stated:

the Company of its responsibility to invest in the system as necessary to provide safe and reliable service. In those instances where the Company invests outside of the approved ISR Plan to meet its regulatory obligations, the Commission is not bound by the ISR cost recovery mechanism, but instead, may exercise its traditional ratemaking and oversight authority that has been in place for numerous decades to determine the appropriate method and timing of cost recovery.

Following the Commission's decisions in the above-referenced matters, it opened a docket to review RI Energy's budgeting process to develop a new budgeting and reconciliation framework. A series of technical sessions was conducted, and draft frameworks were exchanged and reviewed.[27] The record in this docket continued that exchange of information and this order implements the new framework. The new framework recognizes the Company's responsibility to invest in the distribution system to provide safe and reliable service while at the same time assuring that the Company is managing its projects and annual budget in a way that aligns with the Commission's responsibility to ensure just and reasonable rates.

In general, there are three primary differences between the pre-fiscal year 2025 construct and the one approved by this order. First, instead of setting a non-discretionary budget that reconciles to actuals and a discretionary budget that reconciles to the lower of

> [T]he inclusion of reclosers within the reliability blanket in the instant reconciliation filing raised a question of whether the Company was attempting to recover for investment in a program that was not contemplated by the FY 2023 ISR Plan and was ultimately rejected from the FY 2024 ISR Plan. Thus, this reconciliation process highlighted concerns raised in Docket No. 22-53-EL surrounding whether modifications should be made to the structure of the ISR budget approval and reconciliation process. Accordingly, the remainder of the hearing explored how the ISR budgeting and planning process worked, whether there could be improvements for clarity of what was being approved each year, and to ensure budgetary discipline in execution without unduly constraining the Company's ability to invest in necessary safety and reliability measures during the year. (Order No. 25131 at 9).

[27] Information can be found on the PUC's website at Docket No. 23-34-EL; https://ripuc.ri.gov/Docket-23-34-EL.

actual spend or a cumulative spending limit, this framework sets one capital spending budget with a "soft cap." The primary difference here is that the Company will need to manage its spending between discretionary and non-discretionary projects to receive full reconciliation to that budget year. Overspending beyond a 2.5% buffer will result in a one-year revenue requirement adjustment applicable to the entire amount exceeding the soft budget cap. Specifically, if the Company's spending exceeds the consolidated budget cap by more than 2.5%, the entire amount of overspend that exceeds the original soft budget cap is used to calculate a downward rate adjustment to the post-year rate reconciliation equal to a one-year revenue requirement lag.[28] During the informal review process, the Commission explored disallowance through rate recovery of the amount of the overspend or exclusion of the overspend amount entirely from rate base until the Company's next rate case.[29] Instead, the Commission is implementing a mechanism that creates a one-year financial consequence for exceeding the budget while allowing the Company to include any prudently incurred overspend in rate base.

Second, although the ISR Plan has previously tracked major projects separately for transparency purposes, the major projects category under the new framework will each have a spending cap. Major projects will be those projects where spending is greater than $5 million. Overspending beyond a 2.5% buffer will result in a one-year revenue requirement adjustment. If total spending on a major project exceeds the project's budget by more than 2.5%, the entire amount of overspend that exceeds the original soft budget cap will be treated as if that amount was being put into service in the fiscal year. A revenue requirement will be

[28] Typically, in the first year when plant goes into service, the Commission has used a "half-year" convention for the revenue requirement. However, this special adjustment calculates a full year revenue requirement for purposes of the downward rate adjustment.

[29]

calculated on the entire overspend in the same way that the overall budget described above is implemented. The Company's revenue requirement will be reduced in that Fiscal Year's reconciliation filing by an amount equal to the calculated revenue requirement associated with the overspend.

Third, instead of operation and maintenance (O&M) costs being reconcilable up to the full spending (even if in excess of the approved budget), the new framework sets separate budgets for Vegetation Management, the VVO/CVR program, and an Inspection and maintenance costs, each with 10% over-spend buffers. If total spending exceeds the applicable budget by more than 10%, the entire overspend that exceeds the soft budget cap will be disallowed. Unlike rate recovery of capital expenditures, these costs are O&M expenses which are not placed in rate base under traditional rate accounting principles. Therefore, the overspend is simply not recoverable in rates through the ISR.

The new framework was also designed to track study costs separately. Accordingly, the Commission included a separate line item for a $200,000 fiber study that is separately tracked. Approval of the study does not represent a finding that any related fiber investment is needed, prudent, nor eligible for cost recovery. The Company will be required to make a filing in a future case for any investment for which it seeks cost recovery together with the appropriate analysis.

The Company's most significant concern with the single capital budget approach was that it would require them to manage discretionary spend against non-discretionary spend. The Company's testimony on this issue reflected a philosophy that if an investment will not be subject to reconciliation relative to the year in which the spending occurred, the Company might shut it down midstream, even though the Company provided testimony that the investment made in the program year is necessary for the provision of safe and reliable service. At the hearing, Ms. Castro stated:

> So if our nondiscretionary portfolio were to go over budget based on what we had put in, historically, we did not pull back on our discretionary to manage that in totality. And the reason behind that, which we feel very strongly about, is because -- well, several reasons, one of them is, you start to defer important discretionary asset condition and system capacity work that is required to maintain the safety and reliability of the system. But also, if you were going to do that, manage it in totality, I mean, you're asking me that, if I'm starting to go over budget in my nondiscretionary, I actually have to potentially stop work on my discretionary….So there's a, there's a pretty big implication to having to manage this in totality, whereas if you're starting to go over on your nondiscretionary, to pull back on your discretionary.[30]

Starting and stopping work for unexpected deferrals due to budget concerns, according to Mr. Constable and Ms. Castro, would lead to increased costs over the long term.[31,32]

The idea that the Company would cease investment in the middle of a discretionary project because a non-discretionary project would cause total spend to exceed the soft cap and result in a one-year lag in rate recovery is simply not credible – nor would such an action likely be considered prudent.[33]

The Commission finds the new budget framework that introduces a potential one-year cost recovery lag for spending in excess of approved budgets is reasonable because it is consistent with both the construct of the ISR statute and principles of traditional ratemaking. To recap, the ISR statute requires reconciliation of costs to the annual budgets approved by the Commission; it does not, however, limit the Commission's ratemaking authority over costs in excess of those approved budgets. The approved budget framework should balance

[30] Hr'g. Tr. at 434-35.
[31] *Id*. at 436.
[32] *Id*. at 439.
[33] See Hr'g. Tr. at 437-40.

the ISR's goal of facilitating consistent levels of investment in the system that are needed for safety and reliability with the need to hold the Company accountable to its approved budgets.

B. Asset Condition Adjustments

1. Spare Transformers and Mobile Substations

RI Energy proposed a new multi-year plan to purchase spare substation transformers and mobile substations to address system contingency issues that result in a loss of power to customers. As described by the Company in its filing for each program, "the Rhode Island Energy distribution system is designed for N-1 contingency situations. As such, for a loss of a power transformer, load is expected to be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair/replacement of the failed transformer."[34]

The transformer proposal was to procure twenty-three new spare transformers, purchasing three in FY25, and five more in each of the subsequent four fiscal years. The company indicated that it would use a Poisson Probability Distribution to calculate how many spare transformers are needed to maintain a system reliability of 0.995.[35] The Company contended that this was an IEEE standard. The company indicated that it would prioritize the purchase of the spare transformers based on the greatest amount of spare transformers in-service, the ability to supply power to critical customers, and at substations that have the greatest amount of load at risk.[36] As an alternative, the Company considered

[34] RI Energy FY 2025 Electric ISR Plan at Bates 147, 150.
[35] This threshold means that the Company strives to have at least a 99.5 or better probability of having enough spares to maintain reliability over a certain three-year period. Looking at one example, the Company was planning to purchase two spares because while there was a 96.31 chance that the Company would only need one spare, but it did not meet 99.5 percent standard. Hr'g. Tr. at 141-42 (Mar. 13, 2024).
[36] *Id*. at 147-48.

and rejected lease agreements with neighboring utilities as suboptimal due to typical clauses in such agreements allowing the owner to re-call leased equipment if a failure occurs on their distribution system.[37]

In his testimony, Mr. Booth indicated that the Division supported the $736,000 budgeted for the purchase of spare transformers in FY 2025 but did not support a full multi-year program. He advised that the Division would continue to work with the Company to better understand the real risk facing the Company and whether all of the spare transformers are needed on the proposed schedule. He specifically questioned the Company's strategy of having a spare transformer available for each transformer configuration 99.5 percent of the time. Contrary to the Company's assertions, he advised that there is not an industry standard for the likelihood that a spare will be available when a transformer malfunctions. He also questioned whether RI Energy finds it necessary to purchase certain spare transformers because of the transition from National Grid ownership to PPL ownership where it appeared The Narragansett Electric Company appears may have lost synergies that existed under that ownership. If that is a main driver for the need for the additional substations, Mr. Booth suggested further review should be done to determine whether ratepayers should have to bear those costs or if they should be considered merger related costs excluded from the Company's revenue requirement.[38]

During the hearing, questions probed the validity of the Company's statistical analysis and assumptions. There were also questions about the need for a second spare transformer in one example where the purchase of one would result in the Company

[37] *Id*. at 148.
[38] Booth Test. at 11 of 22; Report at 27-33.

meeting a 96% standard. It was at the hearing where RI Energy witness also indicated that there was a lease agreement in effect with National Grid for at least the next three years.[39]

The mobile substation proposal was to procure three mobile substations and a mobile regulator in addition to the two mobile substations it already owns. According to the Company, it would order all three mobile substations and the regulator in FY 2025 with an expected delivery date in FY 2028.[40] The Company indicated that not purchasing these assets would leave certain feeders at risk of not having a solution within 24 hours of a loss of load. As with the spare transformers, the Company considered and rejected lease agreements with neighboring utilities as suboptimal due to typical clauses in such agreements allowing the owner to re-call leased equipment if a failure occurs on their distribution system.[41]

Mr. Booth advised that he generally supported the purchase of mobiles substations and the regulator but that the Division only supported the purchase of one mobile substation in FY 2025 to allow for further assessment of the level of needed inventory. Similar to the spare transformers, he also raised the question of whether these should be ratepayer expenses or merger expenses.[42]

At the hearing, RI Energy's witness, Mr. Weisner testified that all three of the proposed mobile substations are necessary because of the loss of availability from National Grid. While there are a couple of transformers in PPL territory that could support the RI Energy distribution substations, they would take too long to arrive after an event.[43] He also advised that the Company is seeking lease agreements with National Grid.

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[39] Hr'g. Tr. at 131-192.
[40] *Id.* at 150-51.
[41] *Id.* at 151.
[42] Booth Report at 51 of 112.
[43] Hr'g. Tr. at 111-113.

After a review of the evidence in the record, the Commission accepted the Division's recommendation, approving a budget of $736,000 for the spare transformer purchases in FY 2025, but specifically did not approve future spending. Similarly, the Commission approved a budget for the purchase of one mobile substation. Both decisions were subject to further review of appropriate cost recovery consistent with the Division's recommendation. The Commission notes that Mr. Booth's testimony advised that the Commission may want to review whether these costs should be ratepayer or transition costs[44] and further represented that "the Division will also review whether some of the cost of spare equipment should be considered transition costs borne by PPL."[45] The Commission agrees that these costs should be reviewed and looks forward to considering the Division's conclusions from their review.

As part of the FY 2026 Electric ISR Plan, the Company should include a better justification for the 99.5% standard, a range of lead times for the spare equipment, particularly the spare transformers, an updated prioritization for the transformer purchases, assessment of an approach that considers availability of spare equipment from neighboring jurisdictions, and any update to RI Energy's success in negotiating lease agreements in FY 2025.

C. System Capacity and Performance Adjustments

In the FY 2024 Electric ISR Plan, the Company proposed a grid modernization line item that included funding for 100 reclosers in FY 2024 with a goal of having approximately 500 customers per segment. The Commission found that the Company had not met its burden of proof for inclusion in the ISR budget. In the current filing, the Company separated the

[44] Booth Test. at 11 of 22.
[45] Booth Report at 51.

proposal out into three categories of spending and discontinued the arbitrary customer-count based investment strategy.[46]

1. Engineering Reliability Review

The Company proposed a new Engineering Reliability Review Program (ERR) with a proposed budget of $2,000,000. The Company sought to shift an informal approach to pockets of poor performance to a formal program with a pre-determined annual target and a budget for higher cost solutions. Currently, the Company performs ERRs on an annual basis, and circuits are selected to be analyzed based on reliability metrics which are not heavily impacted by localized issues. This has traditionally been completed under the reliability blanket and other approved programs, for example the cutout mounted recloser program.

According to its filing, ERR will review the five-year reliability data for each circuit, rank each circuit based on their five-year average number of customers interrupted (CI) and customer minutes interrupted (CMI), and propose reliability improvements for the worst performing 5% of the circuits. Any circuits that have been in the ERR program or the CEMI program in the last three years will be excluded as improvements would have recently been proposed. Field Engineers, working closely with Operations Supervisors, will review circuit reliability and event history looking for locations of frequent outages, vegetation issues, a high number of animal contacts, protection concerns, and equipment failures. Field inspections will also be conducted to review system construction and locations for additional sectionalizing, line balancing opportunities, appropriate system hardening locations, and reconfiguration opportunities. Reclosers, crossarm mounted reclosers, tie switches, enhanced hazard tree removal, infrared line surveys, fuse additions,

[46] Hr'g. Tr. at 245-69 (Mar. 13, 2024).

and other reliability improvement tools will be utilized. Projects developed through the circuit reviews and field inspections will be sent to the Design Group and written into job packets to be constructed. The alternative would be to continue to utilize the existing reliability blanket and complete improvement projects as they arise.[47]

Following a review of the record developed in discovery, testimony, and at the hearing, the Commission ultimately declined to approve a budget for the creation of a new ERR program which reduced the capital budget by $2,000,000. The work in this category is currently conducted under the blanket project line item and the Company advised that it was increasing the spending limit on blanket projects, meaning the Company can continue to pursue the solutions where needed.

Ultimately, the Company needs to better define the scope and parameters of the program so that the design of the program includes accountability to outcomes and not just the equivalent to action action-based measures. An answer to a question posed during the evidentiary hearing highlights the potential problems with a program that simply chooses to invest in a certain number of feeders each year, in this case 5% of the worse performing feeders, or 20 annually. When asked whether the Company would still pursue ERR spending if, theoretically, every circuit was performing better than the regulatory targets, Mr. Constable answered yes.[48] His basis appeared not to be a system reliability need-driven answer, but a “customer expectation” answer. He stated that customer expectations keep getting more demanding.[49] While a system reliability need is a basis for ISR rate treatment, investment simply based on more demanding customer expectations, absent an objective basis, is not.

[47] FY 2025 Electric ISR Plan at Bates 142.
[48] Hr’g. Tr. at 215.
[49] *Id.*

Furthermore, the proposed selection criteria is simply too broad. There are always going to be feeders in the bottom 5% of performance, but with system improvements, they should have improving reliability results. More problematic is that the evidence in the record shows that feeder performance is not static from year to year. While there are some circuits that are consistently underperforming over multiple years, many that were included in the Company's list have good years and bad years.[50] Mr. Booth testified that spending on a feeder that met regulatory criteria could be justified if a field assessment identified a recurring problem that could be solved by spending money. But, if those persistent issues were not there, he would not support the spending.[51] The selection criteria needs to be more objective to screen for consistently underperforming feeders rather than including a feeder that vastly underperforms in one year but is not in the worst performing feeders in the next.

Finally, before seeking approval of a new program, the Company could propose a multi-year pilot to assess the effectiveness of selection criteria, effectiveness of solutions, and accountability to outcomes. Instead of the broad-based selection criteria the Company proposed, it might consider whether a proposal, for example, where no circuit should be more than 2.5 standard deviations worse than the average circuit could meet its goals. Such a proposal would also need to include budget control and accountability to expected outcomes over time. For example, the primary goal of the program was to reduce the frequency and duration statistics of poor performing distribution circuits. The benefit cost analysis was quite high, but it assumed a 25% improvement in the average frequency and

[50] RI Energy Response to DIV 3-21.
[51] Hr'g. Tr. at 48.

duration measures.[52] However, there was no proposal that the Company would be held accountable to those assumptions.

2. Distribution Automation Recloser Program

The Company proposed a Distribution Automation Recloser Program (DARP) "aim[ed] to set forth the general conditions for installing line reclosers on overhead distribution circuits." According to the Company, this is a reliability focused strategy designed to meet both state regulatory targets and support RI Energy's goal of achieving national and regional first quartile reliability performance. The Company represented that each recloser also acts as a distribution monitor and remote-controlled switch for system management during situations other than interruptions. The Company noted that a number of circuits have interruption frequency and duration values above the regulatory thresholds. The Company indicated that it intends to target circuits with high frequency and duration statistics first. Thus, the plan prioritizes interruption frequency, interruption duration, line exposure, customers experiencing multiple interruptions, existing sectionalization, distributed generation penetration, and pending construction activities. The Company proposed an initial group of 166 reclosers with circuit frequencies greater than 1.5.[53] The program was described as "a reliability-focused strategy designed to meet both state regulatory targets and support RI Energy's goal of national and regional first quartile reliability performance."[54]

In its filing, documentation to support the program noted that:

> Rhode Island Energy has been meeting its state regulatory reliability performance targets as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). However, the company's distribution system reliability has been worsening over time…Additionally, a

[52] RI Energy Responses to PUC 3-30, 3-26, 9-8; DIV 7-7.
[53] FY 2025 Electric ISR Filing at Bates 99.
[54] *Id*. at 158.

> subset of circuits have CKAIFI and CKAIDI values above the regulatory criteria (Figure 3). With the near-term addition of an ADMS which enables FLISR capabilities, this trend is forecasted to reverse with investment in reclosers to improve sectionalization, by reducing the number of customers initially impacted by the interruption. The Company intends to target circuits with high frequency and duration statistics first.[55]

In contrast to the above statement about worsening system reliability, reliability reports showed that not only has RI Energy been meeting its regulatory criteria, the last several years have had better performance results,[56] and when conducting a statistical analysis over the eleven-year period 2013-2023, there is no trend.[57]

The witnesses explained that to reach consensus with the Division, the Company had agreed to provide the Division with information prior to progressing any recloser installations as part of the Customers Experiencing Multiple Interruptions (CEMI), (discussed below) Engineering Reliability Review (ERR) and DARP Programs."[58] DARP and ERR were the subject of many data requests from the Division and Commission, as well as a topic at the hearing. The Company and Division had ultimately agreed on a budget that would result in 88 reclosers on 23 circuits that had a minimum Average Circuit Interruption Frequency Index (CKAIFI) of 2.0.[59] Customers on these circuits experience at least twice as many outages than those within the regulatory targets which is twice as often as the system average.

In his testimony, Mr. Booth explained that the purpose of the Division's pre-review of each of the Company's recloser investments was to address his concerns that the DARP

[55] FY 2025 Electric ISR Filing at Bates 158-59.
[56] RI Energy Test. at Bates 88-89; Compare RI Energy Response to PUC 3-17 (SAIDI 53.07; SAIFI 0.771) with Annual Service Quality Reports for calendar years 2020 (SAIDI 69.1; SAIFI 0.945), 2021 (SAIDI 68.8; SAIFI 0.949), and 2022 (SAIDI 62.48; SAIFI 0.866). The SAIDI regulatory target is 71.9 minutes, and the SAIFI regulatory target is 1.05.
[57] RI Energy Response to PUC 5-11.
[58] RI Energy Test. at Bates 16.
[59] Hr'g. Tr. at 201 (Mar. 13, 2024).

includes areas of minimal justification, reliance on generalized benefits to support advancement of reclosers, the lack of an options analysis and the Company's approach to defaulting to reclosers as the reliability solution without analyzing the root cause of the analysis. He expressed concern that the investments were being proposed simply because the technology was available without an adequate determination of need.[60] Unjustified investment, according to Mr. Booth is of particular concern because it contributes to increasingly expensive electricity rates. Therefore a review of the proposed pace of investment is warranted. Finally, Mr. Booth contended that the Company was comingling the expected costs and benefits of various programs making it impossible to distinguish whether it is necessary and cost-effective to consider a minimum of two to three advanced reclosers with its fault location, isolation, and service restoration technology in addition to mainline reclosers where necessary.[61]

At the hearing, Mr. Booth testified that the Division would not have supported the DARP or ERR programs had the Company not agreed to the pre-review.[62] The Commission finds that no real consensus was reached between the Company and Division on this spending program if the Division needed to have its consultant review each investment before it is made. Such action improperly shifts investment decisions and accountability away from the Company and onto a regulatory authority, in this case, the Division. Over the long-term, such shift would likely impede the Commission's ability to receive an independent analysis of Company investment and management decisions. Therefore, the Commission does not support such a condition.

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[60] Booth Report at 76.
[61] Booth Report at 84.
[62] Hr'g. Tr. at 75 (Mar. 19, 2024).

As a result of the evidence in the record, the Commission ultimately denied funding of a newly created DARP and reduced the capital budget by $5,957,000, finding that reclosers needed for specific safety and reliability needs can be executed in the normal course of business. 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.[63] 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.

3. CEMI-4

The Company proposed an expansion of the CEMI-4 (Customers Experiencing Multiple Interruptions) program approved for FY 2024 into a full program with a greater than 100% increase in the budget line item. The Company filed the same description as last year:

> System and Circuit Average Interruption Frequency Indices 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% of the Company's customers experience four or more interruptions in a rolling twelve-month period. The CEMI-4 Program will identify and fix reliability issues for customers experiencing significantly poorer service than system or circuit averages.[64]

When the proposal was originally approved, the Commission noted that it was a limited budget and the Commission coupled approval with tracking and reporting requirements. This was important because of Mr. Booth's stated concerns in that docket that

[63] RI Energy's Response to RR-3 and RR-9.
[64] FY 2025 Electric ISR Plan at Bates 73.

the proposal overlapped with other initiatives such as the worst performing feeder program and vegetation management pockets of poor performance. The reporting requirements were designed as an attempt to understand how the Company was assessing need, alternatives, and meeting the desired outcome of better performance for customers. However in this filing, prior to even having one full year's results, the Company proposed to more than double the budget and expand the program while maintaining that the same 12% of the Company's customers are affected, despite approval of the pilot spending in the prior year.[65]

A review of the record showed that the justification for the program is the same this year as last year. Based on discovery responses, CEMI-4 appears to have worked as anticipated when approved by the Commission. While the Company's CEMI-4 performance falls into the 3rd quartile for the 3-year and 5-year averages through 2022 (with 2022 in the 1st quartile), excluding major storms puts the Company into the 1st quartile for all three measures (2022; 3-year; and 5-year).[66] Before expanding a program, the Company will need to show how the program is performing over the initial three-year reporting period, design it not for a number of circuits, but as a budget-based program with cost controls and accountability measures.[67]

Finally, because this was originally proposed as an alternatives-analysis and not a pure recloser program, whereas this year's budget appears to be yet a third recloser investment proposal with possible alternatives included.[68] This has called into question whether the BCA filed in Docket No. 22-53-EL (FY 2024 Electric ISR) is still a reasonable analysis for the new

[65] RI Energy Response to PUC 3-28; DIV 1-5.
[66] RI Energy Response to DIV 3-8; DIV 3-16; DIV 3-20.
[67] When assessing need, it is important to understand how the reliability measures are being considered. For example, major storms account for 35% of customer interruptions and including them in the analysis of CEMI-4 leads to a result of 11.46% of customers impacted. Again, the Company is seeking to meet its internal measure of the top percentile of performance among its peers. (RI Energy Response to DIV 3-8; DIV 3-16; DIV 3-20).
[68] RI Energy Response to DIV 3-26; PUC 3-22; DIV 3-28.

proposal. Finally, the Company is cautioned not to place over-reliance on the economic loss calculations from the ICE calculator without further analysis of the inputs and assumptions built into the model.[69]

D. 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.

E. Compliance Filing

On March 27, 2024, the Company submitted a compliance filing to reflect the Commission March 26, 2024 decisions. At an Open Meeting held on March 28, 2024, the Commission reconsidered approval of the previous vote setting the approved budget because the amount was misstated in the Motion. The Commission then approved a total capital expenditure budget of $131,569,000 to reflect the appropriate calculation of the downward adjustments from the Company's proposal. During the Open Meeting, Commissioner Anthony noted the Commission did not approve EER and DARP. However, in its compliance filing, Rhode Island Energy included line items for these two programs with zero budget. This is not consistent with the Commission's decision as these programs should not be included in the budget at all and Rhode Island Energy is not authorized to reallocate funds from other line items to EER or DARP. Following this discussion, the Commission approved the Compliance Filing which had the correct calculation of the capital budget.

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[69] See Hr'g. Test. 241-44 (Mar. 13, 2024).

Accordingly, it is hereby,

(25178) ORDERED:

1. The Narragansett Electric Company d/b/a Rhode Island Energy's FY 2025 Electric Infrastructure, Safety and Reliability Budget and Revenue Requirement, filed on December 21, 2023, is hereby rejected.

2. A capital spending budget framework is adopted that:
(1) tracks major projects equal to or greater than $5 million in overall spending, separately with a project-based budget cap which is based on the construction phase estimate and allows a 2.5% project-based budget buffer;
(2) tracks study costs separately;
(3) sets a consolidated budget for the remaining spending categories of Customer Requests/Public requirements; Damage/Failure; Asset Condition; Non-Infrastructure; and System Capacity & Performance where the consolidated budget, exclusive of approved study costs~~,~~ represents a soft budget cap with a 2.5% buffer; and
(4) applies a one-time budget overspend penalty as follows:
(a) if the Company's spending exceeds the consolidated budget cap by more than 2.5%, the entire amount of overspend that exceeds the original soft budget cap will be treated as if that amount was being put into service in the fiscal year. A revenue requirement will be calculated on the entire overspend above the soft budget cap, ignoring the half-year convention. The Company's revenue requirement will be reduced in that Fiscal Year's reconciliation filing by an amount equal to the calculated revenue requirement associated with the overspend.
(b) if total spending on a major project exceeds the project's budget by more than 2.5%, the entire amount of overspend that exceeds the original soft budget cap will be treated as if that amount was being put into service in the fiscal year. A revenue requirement will be calculated on the entire overspend, ignoring the half-year convention. The Company's revenue requirement will be reduced in that Fiscal Year's reconciliation filing by an amount equal to the calculated revenue requirement associated with the overspend.

3. An Operations & Maintenance budget framework is adopted that sets a Vegetation Management budget, a VVO/CVR O&M budget, and an Inspection and maintenance budget, each with 10% over-spend buffers. If total spending exceeds the applicable budget by more than 10%, the entire overspend that exceeds the soft budget cap will be disallowed.

4. The filed capital budget is reduced by $1,389,000 to maintain the FY 2024 funding level on CEMI-4 of $1,230,000.

5. The creation of a new Engineering Reliability Review program category is rejected and the capital budget is reduced by $2,000,000 because the work can be completed within the Company's blanket category budget.

6. Creation of a new Distribution Automation Recloser Program is rejected and the capital budget is reduced by $5,957,000 because reclosers needed for specific safety and reliability needs can be executed in the normal course of business.

7. The proposed FY 2025 budget on spare transformers and the one mobile substation is approved subject to further review of appropriate cost recovery consistent with the Division's recommendation.

8. The Narragansett Electric Company d/b/a Rhode Island Energy is directed to update the listing of major projects with an updated FY 2025 forecast and estimated construction start including the construction phase estimate for the East Providence Sub (D Sub) project that is commencing construction in April 2024.

9. A total capital spending budget of $131,569,000 is approved for ISR Fiscal Year 2025.

10. A soft budget cap of $118,620,000 is approved for ISR Fiscal Year 2025.

11. A Vegetation Management budget of $13,075,000 is approved for ISR Fiscal Year 2025.

12. A VVO/CVR budget of $365,000 is approved for ISR Fiscal Year 2025.

13. An Inspection & Maintenance budget of $700,000 is approved for ISR Fiscal Year 2025.

14. The Narragansett Electric Company d/b/a Rhode Island Energy shall file a revised Attachment 3 to reflect the Commission's decisions here today. The Company shall add a section for the O&M expense at the bottom to show the total projected spend between O&M and Capital. This Attachment shall be updated and provided with each quarterly report.

15. The Narragansett Electric Company d/b/a Rhode Island Energy shall provide, within 45 days of the Open Meeting decision, a list of each of the electromechanical relays forecasted to be replaced in FY 2025 and indicate whether each is being replaced because it is obsolete (not working or can't find spare parts) or if it is being retired early (although it is still working). In its FY 2026 ISR filing, the Company shall include the same information if it intends to continue seeking approval of the program.

16. The Narragansett Electric Company d/b/a Rhode Island Energy shall include in its FY 2025 Electric ISR Reconciliation Filing and future ISR Plan and Reconciliation filings the CEMI-4 reporting requirements included in the FY 2024 ISR Order.

17. 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%.

18. Contemporaneously with its FY 2026 Electric ISR Plan, The Narragansett Electric Company d/b/a Rhode Island Energy shall file a benefit cost analysis consistent with the Guidance Document issued Docket No. 4600A for all new program proposals and for the VVO program. The BCA for the VVO program shall be specific to the circuits chosen.

19. 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.

20. 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, 2024, with the Reconciliation of the Electric ISR filing with all necessary adjustments to any ISR revenue requirement/reconciliation explained and highlighted.

21. The Narragansett Electric Company d/b/a Rhode Island Energy's Compliance Filing made on March 27, 2024 is approved.

22. 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, 2024, PURSUANT TO OPEN MEETING DECISIONS ON MARCH 26, 2024, AND MARCH 28, 2024. WRITTEN ORDER ISSUED OCTOBER 25, 2024.

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.