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Rhode Island Energy™
a PPL company

September 22, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 5209 - FY 2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing
Responses to Record Requests

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are Company's responses to the record requests issued at the Public Utilities Commission's Evidentiary Hearing in the above-referenced matter.

The Company received an extension to October 18, 2023 to file its response to Record Request No. 2.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 5209 Service List

Record Request No. 1

Request:

Please provide a table showing the variances in the vegetation management to actuals for the last five years (FY 2019-2023). Please show the year, budget amount, actual amount, and percentage variance.

Response:

Please see the table below showing the year, budget amount, actual amount, and percentage variance for vegetation management from FY 2019 through FY 2023.

	FY 2019	**FY 2020**	**FY 2021**	**FY 2022**	**FY 2023**
Budget	$9,800,000	$10,400,000	$10,600,000	$10,800,000	$11,875,000
Actuals	$9,739,000	$10,516,698	$10,685,641	$11,261,563	$12,748,094
% Variance Over/(Under)	-1%	1%	1%	4%	7%

As mentioned in the hearings, the variance in FY 2023 came from the decision to utilize the Outage Analytics Project tool and help direct additional tree work on feeders in the workplan. The tool, available to Rhode Island Energy in the fall of 2022, examined the feeders in the FY 2023 Plan and identified higher outage risks in certain areas. The Company specifically looked at feeders that vendors had not started to see if there were opportunities to utilize the new information effectively. The Company reviewed resourcing with vendors as well as their plans for each circuit and how this additional work would fit in. Upon gathering all this information, the Company prescribed some appropriate additional tree work. This additional tree work included removing more overhanging branches, providing more clearance, as well as targeted tree removal.

Prepared by or under the supervision of: Christopher Rooney

Record Request No. 3

Request:

Please provide a copy of the Long Range Plan referenced in the Company's Reply Testimony.

Response:

Please see Attachment RR-3 for a copy of the latest revision of the Long Range Plan.

Prepared by or under the supervision of: Ryan Constable

The Narragansett Electric Company
d/b/a/ Rhode Island Energy

Electric Infrastructure, Safety, and Reliability Plan 2025 Proposal

Long Range Plan

September 8, 2023

Submitted to:
Rhode Island Division of Public Utilities & Carriers

Submitted by:

Rhode Island Energy™
a PPL company

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1. Introduction and Summary

As agreed, The Narragansett Electric Company d/b/a Rhode Island Energy provides the following information in advance of filing its Electric Infrastructure, Safety, and Reliability (Electric ISR) Plan proposal:

- Ten Year Plan to include
    - Investments that are or will be included in the Electric ISR
    - Years 1 through 5 to include all discretionary and non-discretionary projects, programs, and blanket project cash flows
    - Years 6 through 10 to include large specific projects from area studies, known emerging programs, and inflation adjusted projections of continuing discretionary and non-discretionary cash flows.
- Area Study Status
- Asset Condition and System Capacity and Performance Project Summaries, also termed 'Fact Sheets'

2. Ten Year Plan

Figure 1 – Ten Year Cash Flow

Spend Type	Spending Rationale	Year 1	Year 2	Year 3	Year 4	Year 5
Discretionary	Asset Condition	$60,604	$69,422	$82,738	$47,844	$42,480
	Non-Infrastructure	$1,712	$1,724	$737	$750	$764
	System Capacity & Performance	$49,600	$94,470	$88,732	$70,844	$36,952
Discretionary Total		**$111,916**	**$165,616**	**$172,207**	**$119,437**	**$80,195**
Non-Discretionary	Customer Request/Public Requirement	$58,337	$31,172	$32,066	$33,115	$34,076
	Damage/Failure	$17,013	$17,616	$16,024	$16,415	$16,817
Non-Discretionary Total		**$75,350**	**$48,788**	**$48,090**	**$49,530**	**$50,893**
Grand Total		**$187,266**	**$214,404**	**$220,297**	**$168,967**	**$131,088**

Spend Type	Spending Rationale	Year 6	Year 7	Year 8	Year 9	Year 10
Discretionary	**Asset Condition**	**$41,586**	**$40,303**	**$43,302**	**$41,163**	**$41,970**
	Non-Infrastructure	**$786**	**$810**	**$834**	**$859**	**$885**
	System Capacity & Performance	**$30,374**	**$31,286**	**$32,224**	**$33,191**	**$34,187**
Discretionary Total		**$72,747**	**$72,399**	**$76,361**	**$75,213**	**$77,042**
Non-Discretionary	**Customer Request/Public Requirement**	**$34,008**	**$35,028**	**$36,079**	**$37,161**	**$38,276**
	Damage/Failure	**$17,322**	**$17,842**	**$18,377**	**$18,928**	**$19,496**
Non-Discretionary Total		**$51,330**	**$52,870**	**$54,456**	**$56,090**	**$57,772**
Grand Total		**$124,077**	**$125,268**	**$130,817**	**$131,303**	**$134,814**

The ten year plan was developed in two steps, Long Range Plan Step 1 (LRPS1) which reflects budgeted Capital spend to be proposed in ISR years 1 through 5 and Long Range Plan Step 2 (LRPS2) which reflects Capital Spend to be included in the ISR in years 6 through 10.

LRPS1 includes budgets for specific projects originating from studies such as the Long Range Area Studies, programs like UG cable replacement and URD, blankets like Damage and Failure and Reliability, customer requests, and public requirements.

LRPS2 includes budgets specific for specific projects originating from studies, and inflation projections for years 6 through 10. Inflation is set at 3% for the later year investment projections.

Several factors were taken into consideration while developing the Ten-Year Plan. The following is a breakdown by spending type and rationale.

Discretionary

Asset Condition projects are relatively high in years LRPS1 as a result in study-based issue identification and recommendations. This category scales down as various study related projects are completed in later years of LRPS1. Asset Condition spend is expected to continue into LRPS2 in the low to mid $40 million range. This equals approximately $30 million in base asset condition expenditures which includes underground cable work, underground rural development work, inspection and maintenance work, and blanket level efforts plus approximately $12M in specific asset work that may be identified in future study efforts. It is possible that beyond the ten year period, undergound cable and underground rural development work could be reduced as these programs address the majority of assets of concern. However, there is no reduction predicted in the next ten year period.

Like Asset Condition System Capacity and Performance (SC&P) investments are relatively high in LRPS1 as a result of study-based issue identification and recommendations. SC&P levels are expected to continue slightly above $30 million with base investments, which include core blanket work, volt var optimization work, overloaded stepdown and service transformer work, and targeted reliability review work at approximately $14 million and specific projects of $17.5 million per year. The $17.5 million in specific projects was selected as an appropriate estimate for LRPS2 based on the average study based work for LRPS1 and the understanding that loading, voltage, and reliability work will continue to emerge with the current modest growth rates. Although not included in Figure 1, the Company also considered a possible additional increase in SC&P investments as a result of transportation and heating electrification. While advanced sensing and control investments can be used to mitigate the electric vehicle and heat pump impacts, investments may still be necessary. The Company is using an additional $17.5M per year for LRPS2 as a sensitivity to cover possible electrification adoption. This sensitivity level is not intended to represent an upper bound, but to highlight that transportation and heating electrification can significantly impact future investment levels.

Non-infrastructure work, which includes major tools and some telecom investments, are considered to continue at year 5 levels.

Non-Discretionary

All non-discretionary projects utilize a specific forecast method for LRPS1 and inflation projections for LRPS2.

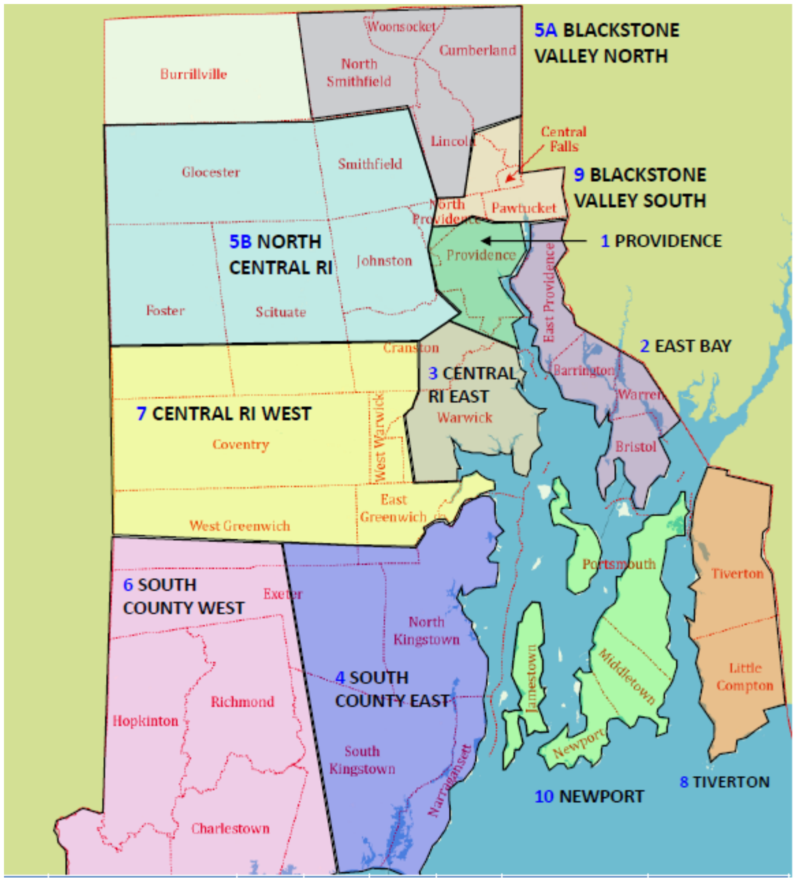
3. Area Studies

Area Planning Studies, also known as Area Studies, are more comprehensive technical reviews of the areas within the Company's service territory. Area Study outcomes result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15- year period.

Areas are defined by distinct geographical and electrical boundaries that have minimal overlap. Studying the system in this manner provides for efficient deployment of engineering resources focused on emerging issues. Should the Company determine that multiple areas have the potential for common system solutions, those areas are combined and/or studied closely together.

An analysis of the state-wide system is only conducted when there is the potential for a fundamental change in the Company's investment strategy. For example, the Company performed a state-wide review to analyze system impacts of load and generation in the Grid Modernization analysis. The analysis is informed by the Area Study solutions and in certain scenarios, identified Area Study solutions may be revised so that the most optimal plan will be executed.

The chart below shows the Company's regional boundaries and study areas.



The chart below shows the statistics by Study area and estimated restudy date.

Study Area Statistics

Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Study Completion Date	Restudy Start
Providence	358	19%	93	16	May 2017	Tentative 2024
East Bay	147	8%	22	7	August 2015	Tentative 2024
Central RI East	204	11%	37	9	September 2017	Tentative 2024
South County East	159	9%	22	10	March 2018	Tentative 2024
Blackstone Valley North	139	8%	27	6	March 2021	TBD
North Central RI	269	15%	35	10	March 2021	Aug 2023
South County West	98	5%	14	5	October 2021	TBD
Central RI West	167	9%	29	10	May 2021	TBD
Tiverton	36	2%	4	1	May 2021	TBD
Blackstone Valley South	171	9%	54	8	October 2021	TBD
Newport	105	6%	42	11	December 2021	Aug 2023 - Partial
Totals	1,853	100%	379	93		

Restudy start dates may change based on various system assessments that inform the prioritization of future studies.

3.1. Future Study Efforts

The Company has explained in past discussion that while the area study process is intended to follow a 5-year restudy timeline, system conditions should ultimately be the deciding factors for restudy. The Company will appropriately schedule the restudies based on emerging loading, reliability, and system performance issues, new customer interconnections, new asset condition and operational issues informed by subject matter experts in Engineering and Operations.

RI Energy is starting study efforts for the following areas:

<u>North Central RI (NCRI)</u>
Although the Northwest RI (NWRI) study was recently completed, the NWRI study was a combination of portions of two other study areas, the western portions of Blackstone Valley North and the northwest portions of North Central RI areas. The southeastern portion of North Central RI includes the town of Johnston which was not included in the NWRI study. Johnston has experienced recent large load and generation applications and interconnections. Furthermore, the Johnston substation has had high utilization (70+% of loading versus ratings) for the recent past. Loading and contingency concerns are emerging for the southeastern portion of the NCRI study area. The recommendations of the NWRI study will be considered to ensure there is no overlap of investments.

<u>Newport</u>
Although recently studied, there are growing concerns about the Gate 2 substation assets within the Newport study area. The Gate 2 substation also has access concerns that significantly affect maintenance

and customer restoration times. Large new customer loads in the southern portion of the study area are putting a strain on limited 4kV capacity.[1]

Providence
The Providence Area Study was last completed in 2017 and the recommendations are still in progress. This effort revisits later period issues identified in the previous study and will build upon the current study recommendations. Specifically, electric facilities located in the East Side of Providence are highly loaded and will likely require wire solutions. A study would be required to determine feasibility of adding a new substation, perhaps from Pawtucket, into the north of the East Side and provide capacity to the area and archive objectives such as the retirement of all overhead 4kV lines.

The Point Street substation, which was noted to remain highly loaded in the previous study, continues to be a concern. Additionally, large load interconnections have occurred /are occurring in the remaining 11kV and 4kV areas placing a strain on those facilities.

The company has identified asset condition issues at the 23kV Admiral Station A study will be required to determine the feasibility of one-for-one replacement, a rebuild of the station for 35kV operation to allow for greater delivery capacity, or other options.

Lastly, there are highly utilized facilities in the western portion of the study area that borders with Johnston and this restudy effort will be coordinated and aligned with the NCRI effort described above.

These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

East Bay
During the East Bay Study an Non-Wires Alternative (NWA) solution was proposed to solve contingency problems at the Bristol Substation. However, after soliciting the market for NWA solutions it was deemed infeasible due to a technically insufficient proposal. Therefore, the Company is choosing to restudy the southern portion of the East Bay area. In addition to the Bristol contingency loading issue, the 23kV assets at the Warren Substation will be reviewed. These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

Central RI East (CRIE)
Drumrock substation asset condition issues raised by Operations need to be reviewed. The Lincoln Ave substation has a high utilization (70+% of loading versus ratings) for the recent past and some feeder contingency issues. The 2222 and 2226 supply lines feeding Warwick substation have contingency issues in the event of an outage of either line. These issues will be further monitored and could lead to kicking off a new area study potentially in 2024 or 2025.

South County East (SCE)
The South County East study area was last studied in 2018. This area is actively being monitored for potential new Quonset Area loads within the next ten years, though the actual loading levels are not confirmed. This coupled with some asset condition/operational concerns with portions of the sub transmission supply system could lead to kicking off a new area study potentially in 2024 or 2025.

[1] The Gate 2 grounding transformer replacement will still be required due to immediate asset needs and the importance of this equipment to the protection system.

3.2. Managing Overlap and Avoiding Redundancy

As described above, when the Company determines that multiple areas have the potential for common system solutions, those areas are combined and/or studied closely together. Past examples include: 1) the coordinated study efforts between the Providence and Central RI East study areas in 2017 that resulted in avoidance of a rebuild of the Sockanosett substation to align with the Auburn substation conversion and rebuild; and 2) the Northwest RI Study, which contained the western portions of Blackstone Valley North and the northwest portions of North Central RI areas to sufficiently analyze the Nasonville transformer contingency issue.

Solution redundancy can occur when two separate parallel efforts address the same concern. An example can be a cable replacement program which recommends direct replacement of a cable and a study solution that eliminates the need for that cable. The Company addresses possible redundancy within the study process by gathering program information and aligning the program recommendation with study recommendations and vice versa. The following highlights a number of investments that were avoided as a result on coordinate comprehensive study efforts:

- The Providence Area Study considered the underground cable program and removed a number of cables that were proposed to be reconductored from the program to avoid redundant spending.
- A number of assets at the Sockanosset substation were scheduled to be raised as a result of the March 2010 flood impacts. This rebuild was cancelled with coordination of the Providence Area Study, which recommended the rebuild of the Auburn substation eliminating many of the Sockanosett assets that were to be raised.
- A Phillipsdale transformer was scheduled to be replaced as a result of the former transformer replacement program. This replacement was cancelled as a result of the East Bay Study recommendations which recommended a rebuild of the Phillipsdale substation and changes to the transformer specifications.
- Energy Management System / Remote Terminal Unit (EMS/RTU) work at various 4 kV substations were cancelled as a result of many study area recommendation that converted or eliminated these 4kV stations. Many of these stations would have required significant rebuilds with the EMS/RTU work

3.3. Avoiding Early Obsolescence

Early obsolescence can occur when certain devices or technologies are deployed and are replaced by a newer device or technology well before the expected asset life. The focus of this concern is often associated with control and protection systems. As the Company performs each study, subject matter experts are consulted to inform the study of the latest technologies. The technological advancements associated with reclosers and the Companies adoption decisions highlights how early obsolescence is avoided. The Company began the transition to programmable microprocessor recloser controls in early 2010s. Although, the communication details and programming details evolved between 2010 and 2020, the Company was able to install the core recloser and control by the mid 2010s. Many of these were installed as ‘communication ready’, with no actual radio. However, the control cabinet and wiring was setup for various radio plug-ins. Study recommendation through these early years required installation of equipment with the latest sensors, controls, and communication capabilities per standards. As the radio details were determined, the reclosers did not need replacement, simply a radio install in the ready cabinet. Similarly, as programming details evolved, no reclosers needed to be replaced, simply reprogrammed. With diligent consultation and well thought out deployment decisions the Company has avoided early obsolescence with its recloser assets. Similar considerations have occurred for capacitor controls and relays.

Another type of early obsolescence can occur when study efforts do not consider emerging customer trends or public policy programs. For example, the recently completed Newport Study identified asset condition issues at the Merton Substation with a recommendation to rebuild the station. In parallel a grid modernization study, which considered customer adoption of electric vehicles and heating electrification, noted that the Merton Substation should be converted to a higher voltage to accommodate the possible customer adoption. The Company has deferred the Merton project to further investigate this issue. A similar situation arose for the Tiverton substation. The area study identified the need for a new feeder at the Tiverton substation while the grid modernization review indicated two feeders might be required. In this particular example, upon review of the construction details, no change to the current project was necessary. The first new feeder can be installed without compromising the cost or schedule of the future second feeder installation. The second feeder can be installed if and when the customer electrification adoption actually occurs in a cost effective manner.

3.4. Process to Identify Opportunities for System Reliability Procurement and Historical Outcomes

The distribution system planning team identifies system needs through area studies, and considers the economic and technical viability of non-wires solutions to each system need identified. The non-wires solution may be considered utility reliability procurement (e.g., conservation voltage reduction, volt-var optimization, utility-owned and operated battery storage) or system reliability procurement (e.g., utility-run or third-party demand response or targeted energy efficiency, third-party owned and operated battery storage). All system reliability procurement solutions are non-wires solutions, but not all non-wires solutions are system reliability procurement solutions.

Engineers screen system needs identified in area studies for the potential viability of a system reliability procurement solution. This screening is fully integrated into the planning process and is part of the normal course of business. Screening criteria have been developed in collaboration with stakeholders and are vetted through regulatory oversight of system reliability procurement.[2] These screening criteria are:

- The system need is not an asset condition issue
    - Electric assets that have reached the end of their lifetimes need to be replaced; a non-wires solution (whether system reliability or utility reliability procurement) cannot resolve an asset condition issue.
- The system need is an eligible system need or optimization

[2] The *2024-2026 System Reliability Procurement Three-Year Plan* will be filed for regulatory review on or before November 21, 2023, in accordance with the Least-Cost Procurement Standards. The Company is not proposing any substantive changes to screening criteria previously approved and applied.

    - Eligible system needs and optimization include load relief, reliability, and supply cost mitigation; if the system need is load relief, the amount of load should not exceed 20% of the total load in the are of the defined need.
- There should be sufficient market interest
    - Rhode Island Energy uses a guideline of the wires solution costing at least $1 million as a proxy for whether a system need is likely to gain sufficient market interest.
- There should be adequate time to implement the system reliability procurement solution
    - Rhode Island Energy uses a guideline of at least 24 months before the start date of the system reliability procurement solution implementation to allow for adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the system reliability procurement solution.
- Additionally, be the Company's discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-wires solution exists, assuming the benefits of doing so justify the costs.

These screening criteria are applied by the engineering team to all electric system needs and opportunities for optimizing system performance first in area studies and then annually as system needs are considered for action. System needs that pass the screening then advance through steps to solicit and evaluate the viability of system reliability procurement solutions, which would then be proposed via system reliability procurement investment proposals filed alongside but separate from *Electric Infrastructure, Safety, and Reliability Plans* per the Commission's Least-Cost Procurement Standards.

The table below lists previously identified opportunities for system reliability procurement.

History of System Reliability Procurement

Naming Convention	**Associated Area Study**	**System Need Identified**	**Cost of Next Best Alternative Utility Reliability Procurement**	**Year in which RFP was issued for system reliability procurement solution**	**Types of technology proposed for non-wires solution**	**Order of magnitude cost of non-wires solution(s) proposed**	**Status**
Bristol 51	East Bay	Contingency Load Reduction – 3MW	$2M	RFP issued 2020	Energy Storage	$1.1M	Closed – proposal(s) deemed technically insufficient to meet system need
Tiverton New Feeder - NWA Pilot	None – Pilot	Load Reduction 1.0MW	$2.9M	No RFP, Pilot executed 2011-2016 in collaboration with OER	Targeted Energy Efficiency, Solar	$3.6M	Closed[3]
Tiverton New Feeder	None	Load Reduction 250kW, 1MWH	$2.9M	2017	Energy Storage	$60k to $90k annual budget	Closed – Did not proceed. Equipment Delays and Uneconomical.
Bonnet 42F1 Feeder	South County East	Load Reduction 1.2MW, 25 MWH/yr for 12 years	$570k	RFP issued in 2018 and reissued in2019	Energy Storage , Virtual Power Plant with a mix of solar and backup generators	$1.1M-$5.8M	Closed – proposal(s) more costly than the best alternative utility reliability procurement
Narragansett 17F2 and 42F1 Feeder	South County East	Load Reduction 1.8MW, 76 MWH/yr for 10 years	$1.6M	2018	Energy Storage	$3.8M	Closed – proposal(s) more costly than the best alternative utility reliability procurement
South Kingstown 59F3 and 68F2 Feeders	South County East	Load Reduction 3.1MW, 14+18 MWH/yr for 10 years	$1.7M	2019	Energy Storage, Virtual Power Plant with a mix of solar and backup generators	$2.3M to $28M	Closed - proposal(s) more costly than the best alternative utility reliability procurement
Staples 112W43 Reliability	Blackstone Valley South	High outage frequency and duration averages	Estimate $1.1M	TBD	TBD	TBD	Pending next steps

[3] http://rieermc.ri.gov/wp-content/uploads/2019/05/national-grid-ri-srp-pilot-2012-2017-summary-report_final.pdf

4. Asset Condition Summaries

Apponaug Long Term Plan

Distribution Related Project Number(s):	C087861 Apponaug Long-Term (D-Sub) C087862 Apponaug Long-Term (D-Line)
Substation(s) / Feeder(s) Impacted:	Apponaug: 3F1, 3F2
Voltage(s):	12.47kV
Geographic Area Served:	Cranston, Warwick
Summary of Issues:	Apponaug consists of a 23 kV station and two 12.47 kV modular feeders. It supplies 15 MW of peak load. The station has a history of operational challenges and asset condition concerns. The major concerns are: • The control building needs major repairs and much of the 23 kV control equipment in the building is obsolete. The building contains both asbestos wiring and asbestos panels. • The 23 kV auto-transfer scheme is obsolete and has a history of mis-operation. This has resulted in customer outages due to its failure to operate. • The voltage regulators are in poor condition and consist of non-standard installation. This non-standard installation makes it very challenging to replace the regulators. • The 23 kV disconnect switches are obsolete, unreliable, and often fail to latch close. • The station has no remote status, control and monitoring of switching devices, transformers, voltage regulation and battery systems (no EMS).
Risks	The short-term work has addressed some of the station issues, but risks still remain for the Apponaug assets. The recent #4 transformer failure (July 2023), resulting in approximately 1900 customers interrupted, highlights the ongoing risks. Failure of the #3 transformer, of similar vintage to the #4 transformer, would result in similar impacts. Although not currently overdutied, the temporary 23kV reclosers are near the station fault current levels. As described above, the 23kV air-break scheme is unreliable and does not operate consistently. Additionally, the 23kV switches are on condemned wooden structures. Structure or switch failure can result in the loss of both supplies, interrupting approximately 3500 customers served by this station. Any major equipment issues at Apponaug substation result in transfer of customers to the Warwick substation. The transferred load requires disabling that automatic

	transfer at the Warwick substation placing that station's customers at further risk of interruption. With no supervisory control nor analogue data on the Apponaug 15kV class assets, equipment failures and customer interruptions take additional time to troubleshoot and address. Lastly, the existing control house presents worker safety issues concerning asbestos and lead. The historic designation of the building makes addressing these safety issues more complicated than typical.
Recommended Plan	The recommended short-term plan for Apponaug was to retire the 23k station, remove all 23kV equipment, and install relayed reclosers for transformer protection. This work has been completed. The long-term plan is to rebuild the station with two new 23/12.47 kV modular feeders utilizing standard open air modular feeder construction.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Central RI East Area Study completed September 2017

Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$400	$2,415	$2,375	$1,213	$365					

Centredale Substation

Distribution Related Project Number(s):	C087783 Centredale Sub (D-Sub) C087784 Centredale Sub (D-Line)
Substation(s) / Feeder(s) Impacted:	Centredale: 50J1, 50J3, 50F2
Voltage(s):	4.16 kV & 12.47kV
Geographic Area Served:	Centredale
Summary of Issues:	Centredale is a 23/12.47/4.16kV substation that consists of one 12.47kV feeder and two 4.16kV feeders. The asset condition report identified the following equipment in need of replacement. • 50F2 voltage regulators (clearance issues) • 50F2 station VSA recloser • 23kV air break control equipment • (4) AB motor mechanisms • (4) 23kV air break switches (501, 502, 503, 504) and replace pole structures • (3) 4.16kV breakers are over duty
Risks	The 4kV circuits out of the Centredale substation are electrically islanded. As described above the 23kV assets are unreliable. Failure of certain insulators, potential transformers, and reclosers have a history of damaging other nearby parts resulting in major repair requirements. Failure of any major 23kV or 4kV asset would result in the approximately 1100 customers out for an extended duration until repairs are made or mobile assets installed. Mobile or spare assets, specifically transformers, can take 24 to 36 hours to install. With no supervisory control nor analogue data, equipment failures and customer interruptions take additional time to troubleshoot and address. Lastly, there are many clearance issues at the station affecting worker safety. In some cases, walking by certain equipment breaks minimum approach values.
Recommended Plan	Rebuild the substation with two new modular 23kV/12.47kV transformers and two new 12.47 kV feeder positions. The 4kV distribution loads will be converted and the 4.16kV equipment will be retired. This will eliminate the 4.16KV island and results in approximately 95 kW of peak loss savings and a yearly loss energy savings of approximately 358,000 kWH
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Northwest RI Area Study completed March 2021

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$900	$2,272	$3,316	$1,176	$250					

Phillipsdale Substation

Distribution Related Project Number(s):	C074427 Phillipsdale (D-Sub) C087367 Phillipsdale (D-Line)
Substation(s) / Feeder(s) Impacted:	Phillipsdale: 20F1, 20F2
Voltage(s):	12.47kV and 23kV
Geographic Area Served:	East Providence
Summary of Issues:	Phillipsdale consists of a two transformer 115/23kV substation that supplies a one transformer 23/12.47kV station and several industrial customers with a combined peak load of approximately 30MW. The following concerns exist at this station: • The power transformers are 1960's vintage. T1 transformer is the only transformer in the system with attached coolers. T2 transformer shows significant signs of aging • The 23kV transformer grounding reactors are concrete encased with small visible cracks. There is no spare grounding reactor to respond to a failure. • Transformer 23kV disconnect switches are non-gang operated and are not readily accessible to operate. • The 23kV breakers are no longer reliable. • A timed scheme at the station prevents bus ties from occurring unless disabled. This scheme is complex to operate and is unreliable. The Phillipsdale 23/12.47kV substation consists of non-standard equipment and construction. The following concerns exist at this station: • A single Load-Tap-Changing (LTC) transformer supplies two 12.47kV feeders with pole mounted line reclosers. The LTC is no longer operable and locked in position. The reclosers have a history of poor reliability. • The distribution voltage from this station only phases with Waterman Avenue feeders. This results in a pocket of load being out of phase with the rest of the system and makes maintenance of the station equipment challenging. • The LTC transformer is a delta/zig-zag with no system spare and only a single mobile transformer in the system suitable for this location. A transformer failure would tie up this mobile for an extended period. The Waterman 23/12.47kV station consists of two 10/12.5 MVA transformers supplying four feeders. A number of concerns exist at this station: • The 23kV air-break switch is obsolete.

	• The transformers have sacrificial high side air breaks switches which are obsolete. • The 23kV capacitor bank has an obsolete vacuum switch. • The 23kV equipment is mounted on wood poles. Significant portions, 7.5 miles, of the 23kV sub-transmission system consists of aged pole plant and small wire installed on rights-of-way and congested public roadways. Portions of the right-of-way are along railroads requiring special permits resulting in additional resources and time for planned and emergency work.
Risks	Noting the asset issues above, planned or emergency work in and around the Phillipsdale Substation is problematic. First, the out-of-phase configuration makes any planned and emergency work durations longer than typical. Additionally, customer interruptions occur during setup and conclusion of any work. Secondly, there are a number of major components at the Phillipsdale Substation that upon failure result in immediate and long term risks to the system. For example, if either 23kV grounding reactor fails, there is no spare. If the reactor is bypassed, there is a risk of high fault current that could severely damage the surrounding breakers. Alternately, the station can be placed on one transformer while a new reactor is procured and installed. This places all the area customers at an elevated reliability risk for the greater than 1 year procurement period. Another example is failure of the #3 transformer. If this transformer fails, the customers associated with the 20F1 and 20F2 circuits would be transferred to other area circuits. With no spare[4] for the #3 transformer and current procurement lead times approximately 3 years, those customers plus the customers on the transferred feeders would face increased risk to interruptions until the new transformer can be procured and installed. Any other major equipment failure during this 3 year period would result in significant customer interruptions. Planned work and maintenance would be limited in this area and load and generation interconnections may have to wait until the system is restored to its normal configuration. Existing interconnected generation may be required to be offline for extended periods of time. Similarly, failures of the #1 or #2 transformers would place the Narragansett Bay Commission and all the 23kV customers on a single source until the transformer can be repaired. While a spare transformer exists, the spare would be tied up for the 3 year replacement time exposing the rest of the system to risk. Similarly, failure of either of the 23kV lines sourced from this station places the customers at an elevated reliability risk. These lines are difficult to access with portions along railroad rights-of-way that require permits for planned and emergency work. Repair durations are much higher than other lines and as a result, the 23kV lines have reliability statistics higher than regulatory and IEEE targets Finally, there are a

[4] This is a small spare. The spare would lessen the risk but not eliminate them. The points remain valid.

	clearances issues, particularly with the breakers, that increase planned and repair work durations. As a specific, recent example to the risks described above, on Wednesday May 24th, 2023 a substation crew reported to Phillipsdale Substation to perform maintenance on the 3TR 2 bus breaker. While the crew was switching the breaker out to establish clearance for the work, an insulator broke on the 3TR 2B-2 disconnect. The crew worked out a plan with the Control Center to expand the worker protection zone[5] to make repairs. One of the new tag points, the 1-2 load break, would not operate properly due to failed load break bottles. The clearance had to be expanded again beyond the 1-2 load break and it was not possible to make repairs. The crew was able to get the switch closed but had to install a hold tag due to broken linkage on one phase. This switch can no longer be operated. The insulator on the 3TR 2B-2 disconnects was repaired and placed back in service. The planned 4 hour job turned into a 14 to 16 hour job with significant overtime hours required. The planned breaker maintenance was not completed.
Recommended Plan	Replace the out of phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station. Initial construction would consist of a single 40MVA LTC transformer, straight bus metal-clad switchgear, four feeder positions, and a 7.2MVAR two stage capacitor bank. The ultimate build-out would be two 40MVA LTC transformers supplying straight-bus metal-clad switchgear with a ties breaker, eight feeder positions, and two 7.2 MVAR two-stage capacitor banks. Upon completion of the station rebuild, convert the two remaining 23kV customers to 12.47kV and retire the 23kV station.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	East Bay Area Study completed August 2015

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$200	$6,208	$7,810	$2,018	$514					

[5] When a protection zone is expanded, it includes and deenergizes greater portions of the system with sectionalization and protective devices which places greater strain on the system and increases customer reliability risks.

Tiverton Substation

Distribution Related Project Number(s):	TIV0001 Tiverton Sub (D-Sub)
Substation(s) / Feeder(s) Impacted:	Tiverton: 33F1, 33F2, 33F3, 33F4
Voltage(s):	12.47 kV
Geographic Area Served:	Tiverton
Summary of Issues:	Tiverton is a two transformer 115/12.47kV substation that consists of four feeders. The area is bounded by the ocean on its west and south, by Fall River (MA) to the north, and by non-Rhode Island Energy territory to its east in the town of Westport. The Tiverton Substation has the following asset condition concerns: • The T1 transformer has an oil leak present in the area of the oil pump • The 115kV MOABs are sacrificial air break switches. The arcing horns are a weak spot, and these are not an ideal method of protection of the transformers. • The 12.47kV VCB breakers are nearing the end of their designed operational lifecycle and showing rusting issues. • The control house is infested with mice and could use additional rodent proofing. The control house door needs to have push panic bars installed for worker safety. • Animal protection needs to be addressed by adding guards on the UG cable getaways, adding an animal electric fence, and adding transformer 12.47kV bushing guards. • Obsolete relays and transformer protection
Risks	The greatest risk at the Tiverton substation is with the protection equipment. The relays are obsolete, and the reclosing relays are unreliable. Combined with the rodent issue, if a protection system or relay fails, there is a risk of greater than normal customer impacts. For instance, two feeders in one bay could be affected if the tie breaker protection fails or two feeders off of one bus could be affected if the bus protection fails. Supervisory control of the reclosing relays is currently unreliable. This requires crew dispatch and extends the duration that equipment is in an abnormal configuration. Tiverton also has transformer risks. The transformers have been in service approximately 45 years. Currently one transformer is undersized and the automatic transfer scheme is disabled during the summer months. If the larger transformer fails, approximately 3 to 5 megawatts, 1000 to 1500 customers, could be interrupted until mobile or spare equipment can be deployed. Lastly, Tiverton contains 1980s vintage direct

	buried cross linked polyethylene getaway cables. These cables are in the top 15% of the cables identified within the Underground Cable Replacement Program.
Recommended Plan	The recommended plan replaces all equipment with asset condition issues. The asset condition replacement work includes the replacement of two (2) 115kV MOAB sacrificial air break switches, Six (6) 12.47kV VCB breakers, three (3) sets of voltage regulators (33F1, 33F2, 33F4), rodent proofing and panic bars for the control house, and the addition of animal protection. (The transformer will be further evaluated and are not scheduled for replacement at this time.)
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Tiverton Area Study completed May 2021
Planned Capital Spend ($000)	

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$75	$393	$786	$786	$393	$187				

Central RI West D-Line Asset Condition Issues

Distribution Related Project Number(s):	C088052 Division St 61F2 Reconductoring (D-Line) C088055 Hopkins Hill 63F6 Feeder Tie (D-Line)									
Substation(s) / Feeder(s) Impacted:	Division St: 61F2 Hopkins Hill: 63F6 Chase Hill: 155F8									
Voltage(s):	12.47kV									
Geographic Area Served:	West Greenwich, East Greenwich, Coventry, Exeter, West Warwick									
Summary of Issues:	The Division St. 61F2 circuit has a 1.6 mile stretch along South Pierce Road and Howland Road in East Greenwich, RI with conductor in poor condition due to many splices. The Chase Hill 155F8 tie with the Hopkins Hill 63F6 on New London Turnpike in Exeter, RI consists of approximately 4,700' of difficult to access conductor in poor condition.									
Risks	The 61F2, 155F8, and 63F6 circuits have five year average circuit frequencies of 1.0 , 2.56, and 2.15 respectively, well above Company targets. Circuit durations are 64, 225, and 193 minutes respectively also above Company targets. Reliability is expected to continue at these levels.									
Recommended Plan	The recommended plan to resolve the conductor asset concern on 61F2 is reconductor this 1.6 miles stretch along South Pierce Road and Howland Road with 477 Al SPCR. The recommended plan to resolve the tie issue between 155F8 and 63F6 is to remove this conductor and relocate the tie to Nooseneck Hill Road. This requires the installation of a new 2 way duct bank with 6" ducts for 800' of single phase 1000 Cu underground conductor that will then rise up to an additional 4,800' of 477 AL SPCR to the normally open load break switch that serves as the tie to the Hopkins Hill 63F6 feeder.									
Alternative Plans	See area study report for alternative plans.									
Long Range Plan Alignment	Central RI West Area Study completed May 2021									
Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$424	$554	$1,258	$650	$390	$424				

Central RI West Equipment Replacement

Distribution Related Project Number(s):	C088046 Coventry Sub Relocation (D-Sub) C088047 Hope Equipment Replacement (D-Sub) C085405 Division St T1 & T2 Replacement (D-Sub) C088006 Anthony Equipment Replacement (D-Sub) C088007 Natick Equipment Replacement (D-Sub) C088008 Warwick Mall Equipment Replacement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Coventry: 54F1 Hope: 15F1, 15F2 Division St: 61F1, 61F2, 61F3, 61F4 Anthony: 64F1, 64F2 Natick: 29F1, 29F2 Warwick Mall: 28F1, 28F2
Voltage(s):	12.47kV
Geographic Area Served:	West Greenwich, East Greenwich, Coventry, Exeter, West Warwick
Summary of Issues:	The Central RI West area is made up of six 115kV transmission lines, four 34.5 kV, and three 23kV sub-transmission lines supplying the ten substations in the area. A primary area of concern is with the Drumrock 23kV system. Safety and asset conditions issues at the Anthony #64, Warwick Mall #28, and Natick #29 substations exist including the need to replace transformers, air breaks, circuit breakers, regulators, lightning arresters and various other equipment. The area also has additional safety and asset conditions issues at Coventry #54, Hope #15, and Division St #61. These concerns include transformers, air breaks, and lightning arrestors.
Risks	Anthony – The 23kV devices are obsolete and unreliable, including the wooden structures. Failure of certain arrestors and insulators have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect both supply lines, impacting approximately 2300 customers until field switching can be completed or repairs are made. For failure of either transformer, approximately 1000 to 1300 customers will be affected until field switching can be completed or mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Anthony substation contains 1970s vintage direct buried cross linked polyethylene getaway cables. The 64F2 is in the top 10% of the cables identified within the Underground Cable Replacement Program. Natick - The 23kV devices are obsolete and unreliable. Failure of certain arrestors and potential transformers have a history of damaging other nearby

	parts resulting in major repair requirements. A 23kV equipment event could affect both supply lines, impacting approximately 2300 customers until field switching can be completed or repairs are made. Warwick Mall – The 23kV devices are obsolete and unreliable. A 23kV equipment event could affect both supply lines, impacting approximately 460 customers until field switching can be completed or repairs are made. The Warwick Mall feeders serve an electric island of predominantly commercial customers. Failure of the #1 transformer would require transfer of all customers to the 28F2 circuit with field switching until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Should the regulators fail, they can be bypassed with bus reconstruction. The customers would be without voltage regulation until replacements can be procured which can be up to one year. Coventry – The 23kV devices are obsolete and unreliable, including the wooden structures. A 23kV equipment event could affect the single supply line, impacting approximately 2700 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of all customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Similar impacts could occur but at a lesser duration for failure of the 12kV load break switch. Switching is limit during peak periods due to distribution line capacity constraints. Hope – The 23kV devices are obsolete and unreliable, including the source selector switch. Failure of certain arrestors and potential transformers have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect the single supply line serving each modular feeder, impacting approximately 1200 to 2400 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of the 15F1 customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Division St. – The 34kV devices are obsolete, unreliable, and cannot be used to deenergize the transformer resulting in complex and extended switching. Failure of certain arrestors and potential transformers have a history of damaging other nearby parts resulting in major repair requirements. During peak periods, the automatic transfer is disabled. A 34kV equipment event or transformer failure could affect either bus, impacting approximately 1100 to 2600 customers until field switching can be completed or repairs are made. There are no spare transformers available for the #1 and #2 transformers. For a transformer failure,

	the system would remain reconfigured for up to 3 years. The Division St. customers plus the customers on the transferred feeders would face increased risk to interruptions until the new transformer can be procured and installed. Any other major equipment failure during this 3 year period would result in significant customer interruptions. Planned work and maintenance would be limited in this area and load and generation interconnections may have to wait until the system is restored to its normal configuration. Existing interconnected generation may be required to be offline for extended periods of time.
Recommended Plan	The recommended plan is to address the asset conditions at Anthony #64, Natick #29, and Warwick Mall #28, Coventry #54, Hope # 15, Division St #61. The required replacement work at each station is shown below. Anthony #64 • Replace the 23 kV bus structures • Replace two (2) OCBs • Replace transformer No. 1 and No. 2 • Replace two (2) 23 kV air breaks • Replace 23kV capacitor bank • Replace lightning arresters • Remove all retired 4 kV equipment • Install an animal fence Natick #29 • Replace the 29F2 regulators • Replace three (3) air breaks - 2266, 2230, and 66-30 • Replace the No. 1 and No. 2 station service transformers • Replace the brown porcelain station post insulators and vintage dead-end bells Warwick Mall #28 • Replace transformer No. 1 • Replace three (3) air breaks - 2266, 2230, and 30-66 • Replace the 28F2 regulators – all three (3) phases • Replace the 28F1 regulators – B & C phases • Replace five (5) sets of HPL air break disconnects • Replace the No. 1 and No. 2 station service transformers • Replace lightning arresters Coventry #54 • Replace air breaks/load breaks 541, 542, & 546 • Replace all lightning arresters

<table>
<tr><td></td><td>Replace the No. 1 transformer
Hope #15
Replace the T1 transformer
Replace all lightning arresters and PTs
Division St. #61
Replace both existing transformers – No. 1 and No. 2
Replace air breaks 3311-2T and 3312-1T
Replace all lightning arresters
Install animal protection</td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>Central RI West Area Study completed May 2021</td></tr>
<tr><td>Planned Capital Spend ($000)</td><td><table><tr><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th><th>FY 2028</th><th>FY 2029</th><th>FY 2030</th><th>FY 2031</th><th>FY 2032</th><th>FY 2033</th><th>FY 2034</th></tr><tr><td>3,278</td><td>$5,363</td><td>$8,138</td><td>1,888</td><td></td><td></td><td></td><td></td><td></td><td></td></tr></table></td></tr>
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Blackstone Valley South 4kV Substation Retirements

Distribution Related Project Number(s):	BSVS001 Crossman St #111 Sub (D-Sub) BSVS002 Crossman St #111 Sub (D-Line) BSVS003 Central Falls #104 Sub (D-Sub) BSVS004 Central Falls #104 Sub (D-Line) BSVS005 Centre St #106 Sub (D-Sub) BSVS006 Centre St #106 Sub (D-Line) BSVS007 Pawtucket #148 Sub (D-Sub) BSVS008 Pawtucket #148 Sub (D-Line)
Substation(s) / Feeder(s) Impacted:	Crossman: 111J1, 111J3 Central Falls: 104J1, 104J5, 104J7 Centre St: 106J1, 106J3, 106J7 Pawtucket #2: 148J1, 148J3, 148J5 Valley: 102W41, 102W50, 102W51, 102W52 Pawtucket: 107W62, 107W80, 107W81, 107W85
Voltage(s):	4.16kV and 12.47kV
Geographic Area Served:	Central Falls, Pawtucket
Summary of Issues:	Crossman St is a single transformer 13.8/4.16kV substation that consists of two feeders. Central Falls is a two transformer 13.8/4.16kV substation that consists of four feeders. Centre St is a single transformer 13.8/4.16kV substation that consists of three feeders. Pawtucket #2 is a two transformer 13.8/4.16kV substation that consists of four feeders. There are numerous concerns with the safety and asset conditions issues at the Crossman St, Central Falls, Centre St, and Pawtucket #2 Substations. The concerns on these 4kV substations include transformers, metal clad switchgears, feeder breakers, and lightning arrestors. There are also asset conditions concerns on the distribution lines. On average, over 55% of the poles are older than 40 years old.
Risks	The four 4kV stations form an electric island in the Central Falls and Pawtucket area. Although risks are listed separately, the risks can compound for long duration reconfigurations associated with major equipment failures. The distribution lines that tie these stations have a majority of pole plant greater than 40 years. Crossman **-** The 13kV devices are obsolete and unreliable, including the source selector switch and the wooden structures. A 13kV equipment event could affect both supplies to this station, impacting approximately 2600 customers until field switching can be completed or repairs are made. Failure of the #1 transformer would require transfer of the all the customers to nearby circuits until mobile or spare equipment deployed. Should mobile or spare equipment be used, it will be

	unavailable for other system needs for approximately 3 years. Similar risks exist for the 4kV metal clad switchgear. For extended duration reconfigurations, emergency conversions may be necessary. Central Falls - The #1 and #2 transformers and the 4kV metal clad switchgear are obsolete and unreliable. During peak periods, the automatic transfer is disabled. A transformer failure could affect either bus, impacting approximately 1100 to 1300 customers until field switching can be completed or repairs are made. Metal clad failure could affect all 2400 customers. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. There is no supervisor indication or control at this station, making troubleshooting and repairs more complicated. For extended duration reconfigurations, emergency conversions may be necessary. Centre St - The #1 and the 4kV metal clad switchgear are obsolete and unreliable. A transformer or metal clad event could affect the single supply line, impacting approximately 2000 customers until field switching can be completed or repairs are made. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. For extended duration reconfigurations, emergency conversions may be necessary. Pawtucket #2 - The #1 and #2 transformers and the 4kV metal clad switchgear are obsolete and unreliable. A transformer failure could affect either bus, impacting approximately 400 to 1300 customers until field switching can be completed or repairs are made. Metal clad failure could affect all 1700 customers. There is a transfer trip scheme for the hydro generator that complicates switching and restoration. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Transformer failures can also result in environmental issues associated with the deluge system. For extended duration reconfigurations, emergency conversions may be necessary.
Recommended Plan	The recommended plan is to convert the 4.16kV distribution feeder load to 13.8kV and transfer to surrounding 13.8kV feeders. The surrounding 13.8kV feeders are supplied by the Valley and Pawtucket Substations. Once the transfers and conversions are complete, all the equipment at the substation will be retired and removed. These conversions result in approximately 385 kW of peak loss savings and a yearly loss energy savings of approximately 1,444,000 kWH
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Blackstone Valley South Area Study completed October 2021

RI Electric ISR
Pre-Filing Planning Information

Planned Capital Spend ($000)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
	$1,044	$2,017	$2,457	$2,126	$386					

Other Area Study Projects – Asset Condition - Newport

Distribution Related Project Number(s):	NWPT001 Dexter #36 Equipment Replacement (D-Sub) NWPT002 Gate II Equipment Replacement (D-Sub) NWPT003 Hospital #146 Equipment Replacement (D-Sub) NWPT005 Eldred 45J3 Reconfiguration (D-Line) NWPT006 Dexter 36W44 Asset Replacement (D-Line)
Substation(s) / Feeder(s) Impacted:	Dexter: 36W41, 36W42, 36W43, 36W44 Gate II: 38J2, 38J4 Hospital: 146J2, 14J4, 146J12, 146J14 Eldred: 45J3 Merton: 51J2, 51J12, 51J14, 51J16
Voltage(s):	4.16kV and 13.8kV
Geographic Area Served:	Jamestown, on Conanicut Island, Middletown, Newport, and Portsmouth, on Aquidneck Island, Prudence Island.
Summary of Issues:	The area has numerous concerns with the safety and asset conditions at Dexter #36, Gate 2 #38, and Hospital #146. These concerns include circuit breakers, transformers, switch gear, and lightning arrestors. The Eldred 45J3 and the 4 kV section of the 36W44 on Prudence Island have numerous asset condition and safety concerns.
Risks	Dexter - Failure of a 13kV circuit breaker will affect the relevant circuit, impacting approximately 1700 to 2100 customers until field switching can be completed or repairs are made. The system would be reconfigured for approximately 6 weeks. Gate II – Without the grounding bank, there is no fault current source for ground faults and the protection system will not work as designed. The system would require substantial reconfiguration to put the transformer in sevice without the grounding bank. As a result, this could lead to customer interruptions while the system is rebuilt. After the system is reconfigured, all the area customers will be at an elevated reliability risk for the greater than 1 year procurement period. Additionally, emergency or planned work at this station requires substantially longer durations than typical as a result of Navy access requirements. Hospital - The #1 and the 4kV metal clad breakers are obsolete and unreliable. A transformer event could affect one of the supply lines, impacting approximately 600 customers until field switching can be completed or repairs are made. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years. Failure of a 4kV circuit breaker will affect the

	relevant circuit, impacting approximately 600 customers until field switching can be completed or repairs are made. The system would be reconfigured for approximately 6 weeks. Eldred – The customers served from the Eldred substation currently experience low voltage issues during peak periods. The voltages issues will continue without this asset work which will improve circuit configurations to imrpove voltage. Dexter 36W44 **-** The customers served from this circuit currently experience low voltage issues during peak periods. The voltages issues will continue without this asset work which will improve voltage.
Recommended Plan	The recommended plan is to address the asset conditions at Dexter #36, Gate 2 #38, and Hospital #146. The required replacement work at each station is shown below. Dexter #36: • Replace the existing 13.8 kV, AMCBs, 364T, 36W41, 36W42, 36W43, and 36W44 with VCBs Gate 2 #38: • Replace the existing 23 kV zigzag grounding transformer to address asset condition issues. Hospital # 146: • Replace the existing 23/4.16 supply transformers, 461 and 462 with two (2) 2.8/35 MVA 23/4.16 kV load-tap-changing transformers. The existing 461 transformer will be rebuilt and refurbished and stored as a spare. • Replace all the existing air-magnetic circuit breakers, 146J2, 146J12, 146J4, 146J14, and 4600, with VCBs. Eldred 45J3: • 2,700 circuit feet of single phase overhead primary to be upgraded to 3 phase on Beach Ave • 550 circuit feet of underground single phase primary to be upgraded to 3 phase • Replace capacitor control with an advanced control to allow voltage override on pole 2 Beach Road • Rephase several single phase taps on North Road and Sloop Street • Install 3 single phase 76.2 kVA regulators on pole #135 North Road, Jamestown

	Dexter 36W44: • Reroute the 4 kV overhead primary along the Navy R.O.W. by installing ~1620 circuit feet of 477 Al overhead 3 phase conductor from pole #95 Cliff Road to pole #2-90 Narragansett Pri. Road • Remove the existing recloser pole #95 Navy R.O.W. and install on Cliff Road • Reconductor ~3,000 circuit feet of existing #6 Cu overhead 3 phase primary with 3 phase overhead 477 AL from pole # #2-90 Narragansett Pri. Road to pole # 24 Narragansett Pri. Road
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Newport Area Study completed December 2021
Planned Capital Spend ($000)	see below

FY 2025	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
$766	$3,253	$3,482	$296						

Kingston Equipment Replacement – Asset Condition - Newport

Distribution Related Project Number(s):	NWPT004 Kingston #131 Equipment Replacement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Kingston: 131J2, 131J4, 131J6, 131J12, 131J14
Voltage(s):	4.16kV
Geographic Area Served:	Newport
Summary of Issues:	The Kingston Substation area has numerous concerns with the safety and asset conditions. These concerns include circuit breakers, transformers, switch gear, and lightning arrestors.
Risks	Kingston **-** The 23kV devices are obsolete and unreliable. Failure of certain arrestors have a history of damaging other nearby parts resulting in major repair requirements. A 23kV equipment event could affect the single supply line, impacting approximately 3000 customers until field switching can be completed or repairs are made. Failure of the #1 and #2 transformers or #1 and #2 4kV metal clad switchgears would affect approximately 2200 and 800 customers respectively. Should mobile or spare equipment be used, it will be unavailable for other system needs for approximately 3 years.
Recommended Plan	The recommended plan is to address the asset conditions at Kingston #131 through a station rebuild. Kingston #131: • Replace TR 311 and TR 312 transformers • Replace the existing 23 kV switchgear and reclosers with a 10 position, VCB, breaker and a half scheme, switchgear line up (Six (6), 23 kV circuits, two (2) Capacitor banks, and two (2) transformers). Eight (8) - 23 kV circuit positions • Use five (5) initially for 23 kV circuits • 38K21 from Gate 2-Kingston, 38K21 from Kingston-Hospital T2 transformer, will become radial • Replace the existing 4 kV switchgear with a twelve (12) position, vacuum circuit breakers in a breaker and a half scheme switchgear, with two (2) transformers, six (6) feeders, two (2) future capacitor banks, and two (2) spares (Existing Kingston 131J2, 131J4, 131J12 and 131J14)
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Newport Area Study completed December 2021

Planned Capital Spend ($000)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
	$400	$3,361	$8,403	$1,681	$2,961					

5. System Capacity & Performance Summaries

Fault Location Isolation & Service Restoration (FLISR)

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	One of Rhode Island Energy's primary goals is to ensure a reliable electric system. The main measurement criteria for reliability are System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). These system level criteria can be calculated on a circuit level, CKAIFI and CKAIDI, to find circuits or portions of the electric system performing below acceptable levels. For example, 25% to 30% of the total circuit population have a 5-year average CKAIFI and CKAIDI greater than the regulatory targets of 1.05 and 71.9 respectively. The percent of circuits with poor reliability increases to over 40% when considering a Company frequency target of 0.88.
Recommended Plan	This program will address the circuit specific reliability issues focusing on the current worst performers. To obtain the greatest opportunity for recloser benefits, the circuit ranking will also be influenced by line exposure distance, existing sectionalization, customers experiencing multiple interruptions (CEMI), distributed generation penetration, and ongoing construction activities.
Current Status and Expected In-Service Date	This program will begin in FY 2025 and be implemented over five years.
Alternatives:	Do Nothing: Without this program, the customers on these circuits will continue to experience poor reliability performance.
Long Range Plan Alignment	This program, which uses advanced reclosers in a FLISR scheme, creates a refined solution opportunity for future study recommendations. This refined use of reclosers will be incorporated into future study efforts as a possible tool. Study recommendations which make use of FLISR techniques will be aligned with this program to avoid redundancy and early obsolescence.

	This program will be aligned with other reliability based programs such as the CEMI 4+ Program and the ERR program.									
Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$7,426	$22,441	$17,314	$17,833	$18,368					

Electromechanical Relay Upgrades

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	Generation, transmission, and distribution systems continuously evolve. The equipment monitoring and protecting the power system must also evolve to meet the reliability expectations of customers. Most electromechanical relays are obsolete and spare parts are difficult to find. In addition, these antiquated relays provide no fault record data that would indicate the fault current, faulted phase, and the time/date of the fault event. This information is important to aid in quickly diagnosing the problem and finding a fault located on the power system. Implementation of digital relays will reduce the amount of relays in the system, provide fault/event record data, allow for remote access to program relays or review fault records, are self-monitoring, and will allow for greater flexibility by offering a wide range of protection settings to help coordinate with other devices.
Recommended Plan	The proposed investment to upgrade approximately 205 electromechanical relays to digital relays. Electromechanical relays associated with the 34kV, 23kV and 15 kV class distribution system have been inventoried and assigned to one of five categories based upon upgrade complexity and ease of replacement. • Category 1: These relay replacements will utilize the existing PPL standard where the relays come pre-wired within an outdoor enclosure. Using an existing standard will allow for quick implementation. • Category 2: These relay replacements will require a new standard to be developed due to the substation equipment being incompatible with the PPL relay standard described in Category 1. These relays will be installed within the breaker itself as opposed to being in a separate enclosure. • Category 3: These relay replacements will require a new standard to be developed and is expected to be finalized after the Category 2 standard. This new standard will be for substations that have indoor circuit breakers and relay panels where a full relay switchboard panel design is required. • Category 4: These relay replacements will require the station to be

	rebuilt or relocated due to existing space constraints within the substation yard making it not feasible to replace the relays within the same footprint. Due to the complexity of this work, these relays will be replaced after 2028. • Category 5: This category includes all existing digital relays that will need to be reprogrammed to include additional safety and data gathering capabilities. This reprogramming includes, but is not limited to, adding hot line tag and various SCADA indications on why the device tripped for FLISR.
Current Status and Expected In-Service Date	This program will begin in FY 2025 and be implemented over a five to ten year+ period.
Alternatives:	Do Nothing: Without this program, the relays will become inaccurate and unreliable. This will lead to additional customer and equipment outages.
Long Range Plan Alignment	Consideration of this program will be included in future study recommendations and ongoing substation projects.
Planned Capital Spend ($000)	

FY 2025	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
$1,166	$603	$1,267	$2,513	$1,263					

Other Area Study Projects – System Capacity & Performance – East Bay

Distribution Related Project Number(s):	EB00001 Bristol (D-Sub) EB00002 Bristol (D-Line)
Substation(s) / Feeder(s) Impacted:	Bristol 51F1, 51F2, 51F3
Voltage(s):	12.47kV
Geographic Area Served:	Bristol, Warren
Summary of Issues:	Bristol is a two transformer substation that consists of three feeders. One of the transformers is supplied by 115kV and the second transformer is supplied by 23kV from the Warren Substation. The Bristol area is electrically isolated from East Providence and Barrington area. There are no feeder ties between these areas because of the Barrington River. The river forms a natural barrier that makes feeder ties between the areas neither practical nor economical. There are normal and contingency capacity concerns on the four feeders. The 51F2 and 51F3 feeders are projected to be at the SN rating in 2030 and all three feeders exceed contingency load-at-risk criteria.
Recommended Plan	The recommended plan is to add a fourth feeder to the Bristol Substation. The addition of a fourth feeder will provide normal and contingency support to the Bristol and Warren feeders.
Alternative Plans	See area study report for alternative plans.

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$84	$378	$378							

Other Area Study Projects – System Capacity & Performance – Newport

Distribution Related Project Number(s):	NWPT007 Newport 203W5 (D-Line) NWPT009 Jamestown Capacitor (D-Line) NWPT010 Eldred 45J4 (D-Line) NWPT015 37K22 and 37K33 Reconfiguration (D-Line)
Substation(s) / Feeder(s) Impacted:	Newport: 203W5 Gate 2: 38K23 Eldred: 45J4 Kingston: 131J6, 131J12 Jespon: 37K22, 37K33
Voltage(s):	4.16kV, 13.8kV, and 23kV
Geographic Area Served:	Jamestown, on Conanicut Island, Middletown, Newport, and Portsmouth, on Aquidneck Island, Prudence Island.
Summary of Issues:	Newport is a one transformer 69/13.8kV substation that consists of four feeders. The 203W5 feeders have conductor limiting and voltage concerns Gate 2 23kV is a single transformer 69/23kV substation that consists of three feeders. The 38K23 has contingency voltage issues. Eldred has two modular 23/4.16kV substations. The 45J4 feeder has a contingency voltage issue. Jepson 23kV substation is a two transformer 115/23kV substation that consists of four feeders. The 37K22 has contingency loading issues.
Recommended Plan	The recommended plan to address the Newport conductor limiting and voltage concerns is as follows: Newport 203W5: • Remove the existing stepdown transformer pole #9 Catherine Street, Newport and convert all the downstream load to 13.8 kV to eliminate the voltage issues. • Reconductor all line sections in the conversion area to 1/0 Al. The recommended plan to address the contingency low voltage issues on Gate 2 38K23 is to install a 2700 kVAR, 23 kV switched Capacitor Bank in the vicinity of pole #29 North Road Jamestown. The recommended plan to address the contingency low voltage issues on Eldred 45J4 is to install three (3) single phase 76.2 kVA regulators on pole #199 East Shore Road

	The recommended option to address the contingency thermal loading issues on 37K22 is to parallel the existing underground cables 37K22 and unused sections of the old 37K33 from P. 1 Adelaide St. to MH 266 at the Hospital #146 substation. This option will increase 37K22 capacity from 7.8/9.1 MVA to 18.5/21.6 MVA vs. 12.8 MVA load.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Newport Area Study completed December 2021

Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$580	$449								

Other Area Study Projects – System Capacity & Performance – Chase Hill Common Items

Distribution Related Project Number(s):	SCW0003 Chase Hill Common Items (D-Line)
Substation(s) / Feeder(s) Impacted:	Chase Hill, 155F2, 155F4, 155F6, 155F8
Voltage(s):	12.47kV
Geographic Area Served:	Hopkington and Westerly, RI
Summary of Issues:	Voltage and reliability issues were identified on all of the Chase Hill feeders. The most significant voltage concerns are on the 155F2 and 155F8 circuits. The three year average reliability statistics are: Circuit / CKAIFI / CKAIDI 155F2 / 4.50 / 465 155F4 / 2.77 / 117 155F6 / 1.34 / 137 155F8 / 5.83 / 600 All the circuits have average reliability statistics greater than the regulatory limits of a frequency of 1.05 and a duration of 71.9 minutes.
Recommended Plan	There are several common items necessary to address voltage, power factor, customer, and reliability issues on the Chase Hill feeders – specifically: • Reconfigure the 155F8 by double circuiting with the 155F6 with new 477 AL spacer cable. (approximately 3.5 miles) • Reconfigure Kenney Hill Road woods construction to Grassy Pond Road (~2,500'). (The 155F8 is also a CEMI priority circuit. The construction work above has been coordinated with the CEMI work to ensure no overlap of scope.)
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	South County West Area Study, completed September 2022

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$200	$2,659	$1,906							

Other Area Study Projects – System Capacity & Performance – South County East

Distribution Related Project Number(s):	SCE001 Lafayette 30F2 Feeder Tie (D-Line) SCE002 Wakefield 17F2 Feeder Upgrade (D-Line) SCE003 Wakefield 17F2 Feeder Upgrade (D-Sub) SCE004 Wakefield 17F3 Feeder Relief (D-Line) SCE005 Peacedale 59F3 Feeder Relief (D-Line) SCE006 Lafayette 30F2 Feeder Upgrade (D-Line)
Substation(s) / Feeder(s) Impacted:	Lafayette – 30F2 Wakefield – 17F2, 17F3 Peacedale – 59F3 Kenyon – 68F5 Bonnet - 42F1
Voltage(s):	12.47kV
Geographic Area Served:	Towns of Narragansett, South Kingston and Exeter
Summary of Issues:	The Town of Narragansett is supplied mostly by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. The western section of the Town of South Kingston is supplied mostly by (3) 12.47 kV distribution feeders. Two feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town. The eastern section of the Town of Exeter is supplied mostly by the Lafayette 30F2 feeder. Sections of this feeder are projected to be loaded above summer normal ratings with the limit being 4/0 aluminum conductor. This feeder has no feeder ties suitable to reduce loading below the rating of the 4/0 aluminum.
Recommended Plan	Town of Narragansett: • Reroute the Peacedale 59F4 feeder along Columbia St, and reconductor ~2,700’ with 477 AL Bare and install a normally open recloser with the 17F3. • Modify feeder open points to provide relief to the 42F1 circuit. • To offload the 17F2, reconductor the front end of the circuit along the roadway (Narragansett Ave) with 477 aluminum bare wire. • Replace the 4/0 aluminum bus conductor on the 17F2 feeder with 477 aluminum bus conductor. Replaced the 89-F2 (4T34) 600 Amp air break and transformer fuse with a 1,200 Amp circuit switcher. This will increase the Summer Normal Rating of the feeder. Additionally, a new tie point is created with the 59F4.

	Town of South Kingston • Create a new feeder tie with the 68F5 (continuing the work proposed in the South County West Area study to offload the 68F2) and the 59F3, with ~13,000' of 477 aluminum spacer cable, shifting load over to the 68F5 to offload the 59F3. Town of Exeter • Replaced 4/0 aluminum bare wire on the 30F2 with 477 aluminum bare wire (~10,000') along Ten Rod Road. • Create a new feeder tie between the 30F2 and Hopkins Hill 63F6, by reconductoring ~8,000' of existing 2-phase 4/0 aluminum wire to 477 aluminum spacer cable adding a new pole top recloser at pole 20 on the 63F6 and add a normally open recloser. • .
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	South County East Area Study, completed 2018
Planned Capital Spend ($000)	see below

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$1,684	$6,404	$333							

Engineering Reliability Reviews (ERR)

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	Annual review of 5% of the company's feeders
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	The most commonly used customer-based reliability indices for sustained outages in the electric utility industry are System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index. (SAIDI). SAIFI indicates how frequently the average customer experienced a sustained interruption over a specified time. SAIDI indicates how long (minutes or hours) the average customer was without service over a specific time, typically one year. The metrics are commonly used by utility companies and regulators for system planning, benchmarking, and performance-based rate making. While effective in describing overall system performance, using system averages exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This can lead to uneven reliability performance in areas that do not have the customer counts to statistically influence system averages.
Recommended Plan	The plan is to review the five-year reliability data for each circuit, rank each circuit based on their five-year average number of customers interrupter (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 reviewing system construction and reviewing 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, and other reliability improvement tools will be utilized. Project developed through the circuit reviews and field inspections will be sent to the Design Group and written into job packets to be constructed.
Alternative Plans	Continue to utilize the existing reliability blanket and complete improvement projects as they arise.

Long Range Plan Alignment	This project looks to enhance reliability for our customers and aligns well with grid modernization and will support area study recommendations.									
Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$4,448	$1,030	$1,061	$1,093	$1,126	$1,159	$1,194	$1,230	$1,267	$1,305

Fiber Network

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	Currently, leased cellular communications is used to communicate with automated devices in substations and with automated devices that have been installed on the line. Leased cellular service is limited in bandwidth and is subject to greater interference, especially during emergencies when communication is imperative. Cellular limitations do not offer adequate functionality and add reliability and resiliency system risk.
Recommended Plan	Replace cellular services connecting substations with fiber optic cabling to improve data flow and reliability of communications. The first year amount of $200,000 is to conduct a detailed fiber deployment study that will further develop scope, prioritize deployment, and refine future year execution and spend.
Current Status and Expected In-Service Date	This program will begin in FY 2025 and be implemented over four to five years.
Alternatives:	Do Nothing: Without this program, station communications costs will rise greater than the cost of this program.
Long Range Plan Alignment	Consideration of this program will be included in future study recommendations and ongoing substation projects, however there is expected to be little overlap or impact.
Planned Capital Spend ($000)	

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$200	$12,980	$17,368	$17,368						

IT Infrastructure

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	The proposed underlying IT infrastructure investments in data management, enterprise integration platform, and corporate PI historian are necessary to enable data gathering, sensing, and control functionalities. The Company considers cybersecurity a necessary capability to operate a safe, reliable and cost-effective electric distribution system. Cybersecurity protects customers and electric grid operations from a vast array of threats. As more intelligent devices, including third-party devices, are interconnected, and integrated with utility operations, the number of potential targets increases, as does the need for a robust cybersecurity program.
Recommended Plan	Plan includes investments that will build foundational data management capabilities by enabling enhanced data governance across key datasets including an enterprise integration platform that will provide all the necessary integrations between the various applications such as ADMS, VVO/CVR, corporate PI Historian and GIS. The plan includes investments for operational planning and engineering tools necessary to model and evaluate the distribution system under steady-state and dynamic conditions. This includes three phase load flow, stability, contingency analysis, system restoration modeling, relay modeling, waveform analysis and other key tools for system operations and planning. This plan also includes a cyber services component.
Current Status and Expected In-Service Date	This program will begin in FY 2025 and be implemented over four to five years.
Alternatives:	Do Nothing: Without these investments, certain functionalities will be unavailable resulting in higher long term costs.
Long Range Plan Alignment	The IT infrastructure investments will enable new study tools and new alternative methods to help evaluate the increasingly dynamic electric system. As the functionalities are enabled, the study recommendations will adjust to incorporate those functionalities.

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$2,213	$2,018	$2,998	$4,281						

Mobile Dispatch

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution level voltage
Geographic Area Served:	System Wide
Summary of Issues:	Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customers calls and predicted outage locations. They prioritize "trouble calls" and outages and assign them to appropriate field crews based on capability and location as optimally as possible. ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten "trouble calls" and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near-real time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand. In summary, Mobile Dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.
Recommended Plan	These investments establish a mobile dispatch system and functionality.
Current Status and Expected In-Service Date	This program will begin in FY 2025 and be implemented over four to five years.
Alternatives:	Do Nothing: Without these investments, certain functionalities will be unavailable resulting in higher long term costs.
Long Range Plan Alignment	These investments are related to worker efficiencies. There is expected to be little overlap or impact with study efforts or other projects.

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$107	$98	$171	$196						

Spare Transformers

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	115-13.2kV, 35-11.5kV, 69-13.2kV
Geographic Area Served:	System Wide
Summary of Issues:	The Rhode Island Energy distribution system is designed for N-1 contingency situations. As such, for the 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. Apart from repairing/replacing the failed transformer, the other system restoration options are meant to be a short-term solution to return load to service. System reconfiguration exposes a larger number of customers to outages since feeders will be physically longer. Subsequent failures will result in an outage that impacts a greater number of customers. Temporary equipment is meant to be installed quickly and for short durations. Expecting a mobile substation to be energized for 3-years while a new transformer is being ordered/manufactured will reduce restoration options for ensuing transformer failures at other substations, limit post-fault switching options since mobile substations do not have an overload rating and increase noise pollution since mobile substations are typically louder than standard power transformers. With transformer lead times approaching 3-years, good utility practice drives the need for maintaining an adequate number of spare transformers in the event of a failure to allow the system to return to normal as soon as possible. To calculate spare transformer requirements, a Poisson probability distribution (Reliability Criterion Model) is used since transformer failures are random events and can be modeled as stationary random processes. This model uses equipment failure rate (per year), power transformer lead time, and amount of power transformers in service to indicate how many spares are required to meet a certain system reliability metric. In this case, system reliability is defined as the probability that a spare transformer is available when needed. Rhode Island Energy has evaluated our spare transformer requirements by grouping transformers by voltage class, capacity, and winding configuration to

	standardize and reduce the number of spares that are required. In total, the Reliability Criterion Model indicates that the company will need thirty (30) spare transformers to meet a .9950 system reliability. The .9950 system reliability benchmark indicates that the company will have a spare available 99.5% of the time. This number has been cited by IEEE to be a common benchmark amongst a wide number of utilities. This system reliability metric introduces a small amount of risk that a spare won't be available, but the number of spares needed drastically increases if the company selected a 1.00 system reliability number. In terms of the actual increase in spares needed, the company would go from thirty (30) to sixty-three (63) spares required to meet a system reliability of 1. This would introduce a large increase in upfront capital costs and ongoing maintenance costs. The existing spare transformer inventory stands at seven (7) spare transformers. Understanding that it isn't be feasible to order all twenty-three (23) spare transformers at once, the company has prioritized the spare transformer ordering needs by evaluating the number of in-service transformers (per transformer grouping), load at-risk and transformers serving critical customers. As a result, the company is proposing to order three (3) spare transformers in FY25 with the expectation that they'll be delivered in FY28. The company will then plan on ordering five (5) spare transformers per year for the next four fiscal years (FY26, FY27, FY28 and FY29). If the company does not move forward with ordering spare transformers, there will be many feeders that will have load at risk. Out of the three (3) spares that are being proposed in FY25, if any of the in-service transformers fail, the company does not have a mobile or spare transformer to restore customers. There are approximately ten (10) substations where if a transformer fails, there isn't enough capacity on the remaining station transformer or feeder ties to restore all customers. One of the proposed spare transformers will back up two (2) in-service transformers that supply power to a local hospital and not having a spare transformer will expose the hospital to increased reliability risk. This project is discretionary and not customer driven.
Recommended Plan	The plan is to procure 3 spare transformers in FY25, 5 spare transformers in FY26, 5 spare transformers in FY27, 5 spare transformers in FY28 and 5 transformers in FY29. The company will use a Poisson Probability Distribution to calculate how many spare transformers are needed to maintain a system reliability of .9950. The company will purchase the spare transformers with a priority on spare transformers that have the greatest amount of spare transformers in-service, supply power to critical customers and have the greatest amount of load at risk.
Alternative Plans	The company has evaluated a spare/mobile lease agreement with a neighboring utility and an option to build out the distribution system to allow for greater redundancy. However, while the lease agreement is adequate for a temporary solution to shore up the lack of spare inventory, it is not a thorough

	long-term solution. Neighboring utilities will want to establish a clause to pull back any leased equipment if a failure occurs on their system. This will introduce reliability risks on the company system while other options are considered to restore the system to normal. Building out the system is cost prohibitive and will take much longer to complete.
Long Range Plan Alignment	The spare transformer calculations have considered long-term projects that add and/or remove transformers.

Planned Capital Spend ($000)

FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034
$736	$2,960	$6,860	$8,780	$8,440	$7,980	$4,200			

Mobile Substations

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	34.5x23-12.47kV, 115000V-13200Y/7620V, 115000Y/66400Vx115000V-23000Y/13270x34500Y/19920V & 34/23kV mobile regulator
Geographic Area Served:	System Wide
Summary of Issues:	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. Apart from transferring customers to an adjacent transformer or feeder ties, installing a mobile substation is the quickest solution to restoring customers and returning the system back to normal operating conditions. A mobile substation is a completely self-contained trailer mounted unit and is typically comprised of a transformer, cooling equipment, high voltage and low voltage disconnects, a power circuit breaker, metering, relaying, AC and DC power, and surge protection. Rapid integration into the system and the ability to reuse the mobile substation afterwards at other locations are the most important advantages to maintaining a mobile fleet. In addition, mobile substations can be installed and commissioned in minimal time. Mobile substations are key elements for ensuring continued reliability and supporting the system during serious incidents. Mobile substations are typically used in: 1. Emergency Response. 2. Proactive maintenance. 3. Substation capital projects requiring a transformer to be out of service for a prolonged amount of time. Rhode Island Energy currently owns and maintains two (2) mobile substations at distribution voltage levels (34kV and below). These two mobile substations have a maximum capacity of 5MVA and 12MVA. Out of the approximately two hundred (200) in-service distribution transformers in the system, these two mobile substations can only be utilized too fully support approximately eighty (80) transformers in the event of a failure. The company is planning to purchase three (3) mobile substations and one (1) mobile regulator to address the gap in coverage. The first mobile substation (along with the mobile regulator) will be able to support twenty-three (23) transformers. At the present time, we have two (2) in-service transformers that would cause unserved load in the event of a failure. Procuring this one mobile substation will provide a quick and safe option to restore these

	customers. The second mobile substation will be able to support fifty-two (52) in-service transformers. There are currently nine (9) substations that will have load at risk if a transformer fails. The third mobile substation will support forty-three (43) in-service transformers. All three mobile substations all cover a different subset of transformer voltages and capacities. In addition to supporting restoration efforts, mobile substations are utilized when loading or reliability concerns are introduced because of construction sequencing for capital projects. This typically happens when a transformer is required to be out of service for more than 2 weeks or when the construction is impacting a critical customer or heavily loaded area of the state. If the company does not move forward with ordering mobile substations, there will be many feeders with load at risk where the company will not have a solution to restore those customers within a 24-hour timeframe. Planned capital projects will also need to be re-evaluated to determine if scope needs to be added or schedules extended to account for the absence of a mobile substation to support construction activities. This project is discretionary and not customer driven.
Recommended Plan	The plan is to procure 3 mobile substations and 1 mobile regulator starting in FY25 with an expected delivery date of FY28.
Alternative Plans	The company has evaluated a mobile lease agreement with a neighboring utility and an option to build out the distribution system to allow for greater redundancy. However, while the lease agreement is adequate for a temporary solution to shore up the lack of mobile equipment, it is not a thorough long-term solution. Neighboring utilities will want to establish a clause to pull back any leased equipment if a failure occurs on their system. This will introduce reliability risks on the company system while other options are considered to restore the system to normal. Expanding the system is cost prohibitive and will take much longer to complete.
Long Range Plan Alignment	The mobile substation plan has taken into consideration the long-term plan by evaluating future transformer inventories and capital projects that will require a mobile substation to complete. This plan could change depending on the spare transformer inventory levels.

Planned Capital Spend ($000)	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**	**FY 2034**
	$1,620	$4,860	$9,720							

6. Attachment 1 – Detailed Long Range Plan

Spend Type	Spending Rationale	Jurisdictional Spotlight	2024 ISR Total Budget	2025 ISR Total Budget	2026 ISR Total Budget	2027 ISR Total Budget	2028 ISR Total Budget	2029 ISR Total Budget	2030 ISR Total Budget	2031 ISR Total Budget	2032 ISR Total Budget	2033 ISR Total Budget	2034 ISR Total Budget
Discretionary	**Asset Condition**	Apponaug Sub - CRIE	$0	$400	$2,415	$2,375	$1,213	$365					
		Batteries	$230	$195	$387	$319	$100		$103	$0	$106	$0	$109
		Blanket	$5,220	$6,177	$6,338	$6,504	$6,676	$6,480	$6,675	$6,875	$7,081	$7,294	$7,513
		Centredale Sub - NWRI	$0	$900	$2,272	$3,316	$1,176	$250					
		Dyer St Substation	$0	$15	$0	$0	$0						
		I&M	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,090	$3,183	$3,278	$3,377	$3,478
		NWRI Study	$0	$0	$0	$0	$0						
		Other	$783	$0	$0	$0	$0						
		Other Area Study Projects - BSVS	$0	$900	$0	$0	$0						
		Other Area Study Projects - CRIW - D-Line	$0	$424	$554	$1,258	$650	$390					
		Other Area Study Projects - CRIW - Equipment Repl	$0	$3,278	$5,363	$8,138	$1,888	$0					
		Other Area Study Projects - EB	$0	$0	$25	$0	$0						
		Other Area Study Projects - Newport	$0	$766	$3,253	$3,482	$296	$0					
		Other Area Study Projects - SCW	$0	$0	$0	$0	$1,029	$2,297	$2,536	$478			
		Phillipsdale Substation	$0	$200	$6,208	$7,810	$2,018	$514					
		Providence Study	$0	$492	$5,396	$7,407	$6,293	$9,619	$1,567	$1,516	$3,738	$521	
		ProvSt-Other	$0	$0	$0	$0	$0						
		ProvStudy Ph1A	$0	$0	$0	$0	$0						
		ProvStudy Ph1B	$13,941	$17,483	$1,180	$0	$0						
		ProvStudy Ph2	$1,597	$2,922	$9,400	$7,064	$0						
		ProvStudy Ph3	$0	$0	$0	$0	$0						
		ProvStudy Ph4	$8,776	$7,990	$0	$0	$0						
		Recloser Repl Program	$1,300										
		Reserve	$0	$0	$1,000	$1,000	$1,000	$1,000	$13,000	$13,390	$13,792	$14,205	$14,632
		South St Substation	$0	$0	$0	$0	$0						
		Southeast Substation	$66	$0	$0	$0	$0						
		Substation Breakers & Reclosers	$437	$0	$0	$0	$0						
		Tiverton Substation	$0	$75	$393	$786	$786	$393	$187				
		UG Cable Replacement	$5,500	$5,500	$6,000	$6,000	$6,000	$6,500	$6,695	$6,896	$7,103	$7,316	$7,535
		URD Program	$6,275	$7,008	$7,419	$7,731	$7,831	$7,508	$7,733	$7,965	$8,204	$8,450	$8,704
		UG Improvements	$600	$700	$565	$0	$0						
		Kingston Equipment Replacement	$0	$400	$3,361	$8,403	$1,681	$2,961					
		Merton Equipment Replacement	$0		$816	$2,449	$4,082	$816					
		Substation Power Transformer Spares	$0	$736	$2,060	$3,240	$0	$0	$0				
		Blackstone Valley South 4kV Conversion Work	$0	$1,044	$2,017	$2,457	$2,126	$386					
	Asset Condition Total		**$47,725**	**$60,604**	**$69,422**	**$82,738**	**$47,844**	**$42,480**	**$41,586**	**$40,303**	**$43,302**	**$41,163**	**$41,970**

RI Electric ISR
Pre-Filing Planning Information

Spend Type	Spending Rationale	Jurisdictional Spotlight	2024 ISR Total Budget	2025 ISR Total Budget	2026 ISR Total Budget	2027 ISR Total Budget	2028 ISR Total Budget	2029 ISR Total Budget	2030 ISR Total Budget	2031 ISR Total Budget	2032 ISR Total Budget	2033 ISR Total Budget	2034 ISR Total Budget
	Non-Infrastructure	Blanket	$700	$712	$724	$737	$750	$764	$786	$810	$834	$859	$885
		EV Charging Stations	$0	$0	$0	$0	$0						
		Infra Red Equipment	$0	$0	$0	$0	$0						
		Other	$0	$0	$0	$0	$0						
		Overheads	$0	$0	$0	$0	$0						
		Verizon Copper to Fiber Conversions	$1,000	$1,000	$1,000	$0	$0						
	Non-Infrastructure Total		**$1,700**	**$1,712**	**$1,724**	**$737**	**$750**	**$764**	**$786**	**$810**	**$834**	**$859**	**$885**
	System Capacity & Performance	3V0	$1,095	$540	$0	$0	$0						
		Aqudnck Island Projects	$1,038	$0	$0	$0	$0						
		Blanket	$2,490	$2,605	$2,725	$2,851	$2,983	$3,072	$3,165	$3,260	$3,357	$3,458	$3,562
		CEMI 4	$1,230	$5,312	$1,640	$1,640	$1,640						
		Chase Hill Common Items	$0	$200	$2,659	$1,906	$0						
		Chase Hill Second Half of Station	$0	$0	$1,006	$2,012	$1,006	$1,006					
		East Bay Study	$0	$84	$378	$378	$0						
		East Providence Sub	$1,330	$6,865	$4,429	$5,003	$0						
		Electromechanical Relay Replacement Program	$0	$1,166	$603	$1,267	$2,513	$1,263					
		EMS/RTU	$658	$135	$1,147	$2,350	$750						
		Mainline Recloser Enhancements	$0	$0	$0	$0	$0						
		Nasonville Substation	$1,912	$3,674	$3,717	$0	$0						
		New Lafayette Sub	$750	$910	$5,886	$151	$0						
		Other	$2,041	$1,978	$1,600	$1,600	$1,600	$1,600	$1,648	$1,697	$1,748	$1,801	$1,855
		Other Area Study Projects - BSVS		$0	$0	$0							
		Other Area Study Projects - CRIW	$1,372	$1,550	$1,261	$1,261	$757	$0					
		Other Area Study Projects - Newport	$0	$909	$976	$461	$0						
		Other Area Study Projects - Northwest Rhode Island	$1,933	$0	$0	$0	$0						
		Other Area Study Projects - SCW	$364	$727	$1,442	$2,003	$2,576	$1,147					
		Reserve	$0	$0	$1,000	$1,000	$1,000	$1,000	$17,500	$18,025	$18,566	$19,123	$19,696
		RI.GRIDMOD	$0	$0	$0	$0	$0						
		Staples #112 Reliability Improvements	$400	$680	$681	$909	$0						
		VVO	$0	$100	$8,439	$6,701	$6,701	$6,701	$6,902	$7,110	$7,323	$7,542	$7,769
		Warren Sub	$1,969	$3,376	$2,366	$747	$111						
		Weaver Hill Rd Substation	$1,507	$1,105	$3,054	$3,475	$2,496	$1,229					
		ERR		$4,448	$1,030	$1,061	$1,093	$1,126	$1,159	$1,194	$1,230	$1,267	$1,305
		Other Area Study Projects - SCE		$1,684	$6,404	$333							
		Mobile Substation		$1,278	$3,834	$7,668	$0	$0	$0	$0	$0	$0	
		FLISR	$0	$7,426	$22,441	$17,314	$17,833	$18,368					
		Tiverton D-Line Work	$109	$328	$656	$656	$328	$440					
		ADMS/DERMS Advanced	$0	$0	$0	$3,159	$1,568	$0					
		DER Monitor/Manage	$0	$0	$0	$2,288	$4,043						

RI Electric ISR
Pre-Filing Planning Information

Spend Type	Spending Rationale	Jurisdictional Spotlight	2024 ISR Total Budget	2025 ISR Total Budget	2026 ISR Total Budget	2027 ISR Total Budget	2028 ISR Total Budget	2029 ISR Total Budget	2030 ISR Total Budget	2031 ISR Total Budget	2032 ISR Total Budget	2033 ISR Total Budget	2034 ISR Total Budget
		Fiber Network	$0	$200	$12,980	$17,368	$17,368						
		IT Infrastructure	$0	$2,213	$2,018	$2,998	$4,281						
		Mobile Dispatch	$0	$107	$98	$171	$196	$0					
	System Capacity & Performance Total		**$20,198**	**$49,600**	**$94,470**	**$88,732**	**$70,844**	**$36,952**	**$30,374**	**$31,286**	**$32,224**	**$33,191**	**$34,187**
Discretionary Total			**$69,622**	**$111,916**	**$165,616**	**$172,207**	**$119,437**	**$80,195**	**$72,747**	**$72,399**	**$76,361**	**$75,213**	**$77,042**
Non-Discretionary	**Customer Request/Public Requirement**	3rd Party Attachments	$280	$288	$297	$306	$315	$324	$334	$344	$355	$365	$376
		Distributed Generation	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000					
		Distribution Generation	$0										
		Land and Land Rights	$500	$515	$530	$546	$562	$579	$596	$614	$633	$652	$671
		Meters	$2,605	$2,533	$2,603	$2,638	$2,708	$2,789	$959	$988	$1,017	$1,048	$1,079
		New Business - Commercial	$9,093	$9,366	$9,647	$9,937	$10,235	$10,542	$10,858	$11,184	$11,520	$11,865	$12,221
		New Business - Residential	$7,212	$7,428	$7,651	$7,880	$8,117	$8,361	$8,611	$8,870	$9,136	$9,410	$9,692
		Other	$0	$0	$0	$0	$0						
		Outdoor Lighting	$575	$592	$610	$628	$647	$666	$686	$707	$728	$750	$773
		Public Requirements	$1,249	$3,140	$3,234	$3,331	$3,431	$3,531	$5,491	$5,656	$5,825	$6,000	$6,180
		Regulatory Requirements	$0	$0	$0	$0	$0						
		Tiverton Substation		$14,660									
		Transformers	$5,000	$5,300	$5,600	$5,800	$6,100	$6,283	$6,471	$6,666	$6,866	$7,072	$7,284
		Weaver Hill Rd Substation		$13,515	$0								
	Customer Request/Public Requirement Total		**$27,514**	**$58,337**	**$31,172**	**$32,066**	**$33,115**	**$34,076**	**$34,008**	**$35,028**	**$36,079**	**$37,161**	**$38,276**
	Damage/Failure	Damage/Failure Blanket	$10,940	$11,268	$11,606	$11,954	$12,313	$12,682	$13,063	$13,455	$13,858	$14,274	$14,702
		Hopkins Hill Transformer Failure	$0	$50	$1,300	$0	$0	$0	$0				
		Nasonville Substation Rebuild	$1,092	$1,637	$222	$0	$0						
		Other Damage/Failure	$0	$0	$0	$0	$0						
		Reserve	$979	$1,008	$1,038	$1,070	$1,102	$1,135	$1,169	$1,204	$1,240	$1,278	$1,316
		Storms	$1,950	$3,000	$3,000	$3,000	$3,000	$3,000	$3,090	$3,183	$3,278	$3,377	$3,478
		Westerly T2 Failure	$231	$0	$0	$0	$0						
		Apponaug Transformer Failure		$50	$450	$0							
	Damage/Failure Total		**$15,192**	**$17,013**	**$17,616**	**$16,024**	**$16,415**	**$16,817**	**$17,322**	**$17,842**	**$18,377**	**$18,928**	**$19,496**
Non-Discretionary Total			**$42,706**	**$75,350**	**$48,788**	**$48,090**	**$49,530**	**$50,893**	**$51,330**	**$52,870**	**$54,456**	**$56,090**	**$57,772**
Grand Total			**$112,329**	**$187,266**	**$214,404**	**$220,297**	**$168,967**	**$131,088**	**$124,077**	**$125,268**	**$130,817**	**$131,303**	**$134,814**

Record Request No. 4

Request:

Superseded by Company/Division agreement on reclosers – information on the dollar amount in the revenue requirement associated with the $1.6M reclosers will be included in that agreement.

Response:

Please see Attachment RR-4 for a letter memorializing the Agreement between the Division of Public Utilities and Carriers and The Narragansett Electric Company d/b/a Rhode Island Energy on reclosers.

Prepared by or under the supervision of: Nicole A. Gooding

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280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

September 22, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 5209 - FY 2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

<u>Settlement Between The Narragansett Electric Company d/b/a Rhode Island Energy and the Division of Public Utilities and Carriers on FY 2023 Spending</u>

Dear Ms. Massaro:

This letter memorializes the settlement that was reached between The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") and the Division of Public Utilities and Carriers ("Division") (collectively, the "Parties") during the evidentiary hearing for the Fiscal Year ("FY") 2023 Electric Infrastructure, Safety, and Reliability ("ISR") Reconciliation Filing. Specifically, the Parties agree to the following:

- In consultation with the Division, the Company agrees to remove plant additions equating to approximately $1,733,317 and the related cost of removal associated with the spend on reclosers in the reliability blanket during FY 2023.

- The Division will review and consider supporting the investment in reclosers made by the Company during FY 2023 for inclusion into the FY 2025 ISR Plan. If the investment is ultimately supported by the Division and proposed by the Company as part of the FY 2025 ISR Plan, the Company would accept the regulatory lag associated with the investment.

- The Company agrees to remove $26,729 from the revenue requirement as identified in the Company's response to DIVISION 1-1 related to adjustments stemming from the Company's review of distributed generation projects.

If the Public Utilities Commission ("PUC") approves this Settlement, the Company will submit a Compliance Filing incorporating the above adjustments (along with any other adjustments that may be directed by the PUC) following the Open Meeting that is scheduled for September 26, 2023.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

cc: Docket No. 5209 Service List

Record Request No. 5

Request:

In the FY 2023 ISR Plan at Bates page 101, the Company explained that it "has adopted changes to minimize police detail and flagger costs where possible. This includes removing police detail costs from the Company's Cycle Pruning vendor bidding process and placing these costs into a separate budget account. This providing a more accurate historical basis for discussions with municipalities. In addition, the VM program police protection processes are coordinated with the Company's electric and gas construction departments. The VM program police protection processes are also coordinated with the Company's community relations department so that the Company can discuss police detail requirements with communities and municipalities in advance of performing the work. Additionally, since the Company's tree pruning work is performed by contractors, the Company has added police detail costs to the system used to evaluate overall contractor performance for a fiscal year, thus creating an incentive for contractors to actively focus on police details. To assist with this effort, the Company has also revised its contracting strategies by placing only one contractor in each municipality during a given year. This allows each contractor to develop a relationship with each town, and to better address communications with public safety officials."

a. Please explain how, if at all, this change has impacted the vegetation management budgeting, spending, and variances.

b. Please explain whether this change has had a positive (downward) impact on police detail costs.

Response:

a. In the past, cycle trimming was bid out so that flagging (done by the tree vendor) was included in the price to trim each circuit. By putting the flagging costs and police detail costs into the separate line item provides visibility to what the associated costs are per circuit for traffic control. This change assisted with monitoring vendor performance, as well as showing the actual traffic control costs that were associated with each circuit.

   By keeping good historical traffic control costs by circuit, it highlights where vendors have done a nice job or poor job managing these costs. These historical costs are used to determine which vendors to award work to. For instance, if two vendors were close in their bid for trimming a circuit, however one manages traffic control much better than the other the Company would award to the better performing vendor.

Record Request No. 5, page 2

For the cycle trim bid packages, the Company tries to arrange work so that it is one contractor per area or municipality. This enables the vendor to be more efficient by understanding the local regulations and optimize coordination. For example, the town of Cumberland has a flagging ordinance which allows a vendor to employ a licensed flagger versus using a police officer. If the vendor understands this provision, they can bring in more staff to flag the work instead of hiring a detail officer.

Regarding communication and coordination, the Vegetation Management department is frequently involved in discussions with overhead lines and gas regarding their work, to avoid traffic issues and its related costs. If an area of a circuit can be rescheduled to help avoid another department, it will lead to more efficiencies and keep costs lower.

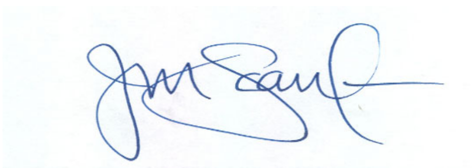
In addition, the Vegetation Management department frequently talks with municipalities to understand what is going on in their communities. There could be construction projects that the Company may not be aware of and could cause cost increases, delays, or create opportunities. A perfect example is on RT 102 in Burrillville. The Nasonville bridge was under construction and closed which created a mile stretch of a major road (Rt 102) in which traffic control needs were significantly reduced as the traffic flowing was drastically reduced.

b. The Company has not quantified the impact on police detail cost. Qualitatively, applying the concepts explained above over time should result in a positive (downward) impact on police detail costs. As the Company moves forward, the key to this and many other line items in the vegetation spend is to improve the specific budgeting for the conditions and areas Rhode Island Energy intends to work in each upcoming plan.

<u>Certificate of Service</u>

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.



____________________________________ <u>September 22, 2023</u>

Joanne M. Scanlon Date

Docket No. 5209 – RI Energy's Electric ISR Plan FY 2024
Service List as of 9/11/2023

Name/Address	E-mail Distribution	Phone
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File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Esq. Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107
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