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Rhode Island Energy™
a PPL company

March 17, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 22-53-EL – The Narragansett Electric Company
Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan
Responses to Record Requests – Batch 1

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's first batch of responses to record requests issued by the Public Utilities Commission ("Commission") during the March 8, 2023 and March 9, 2023 hearings for the above-referenced matter.

The Company received an extension until Monday morning, March 20, 2023, to respond to record requests 9, 18, and 22.

Please be advised that the Company is seeking confidential treatment of the Company's unredacted response to Record Request No. 21, which contains confidential and privileged information. Pursuant to 810-RICR-00-00-1.3(H)(3) and R.I. Gen. Laws § 38-2-2-(4)(A)(I)(b), the Company respectfully requests that the Commission treat Record Request No. 21 as confidential. In support of this request, the Company has enclosed a Motion for Protective Treatment. In accordance with 810-RICR-00-00-1.3(H)(2), the Company also respectfully requests that the Commission make a preliminary finding that the information redacted in the public version is exempt from the mandatory public disclosure requirements of the Rhode Island Access to Public Records Act ("APRA").

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 22-53-EL Service List
John Bell, Division

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

In Re: FY 2024 Electric ISR Plan	)	Docket No. 22-53-EL

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") hereby requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein.

The record that is the subject of this Motion that requires protective treatment from public disclosure is the Company's unredacted response to Record Request No. 21" (referred to herein as "Confidential RR-21") that was filed by the Company on March 17, 2023 in the above-referenced docket. Rhode Island Energy requests protective treatment of this record in accordance with R.I. Gen. Laws § 38-2-2-(4)(B).

I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA.

See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

II. BASIS FOR CONFIDENTIALITY

Confidential RR-21, which is the subject of this Motion, is exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information is likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

Confidential RR-21 consists of financial and commercial information. Rhode Island Energy would customarily not release this information to the public and its submission of Confidential RR-21 is being provided in response to a record request issued by the PUC. Accordingly, Rhode Island Energy is providing Confidential RR-21 to fulfill its regulatory responsibilities.

In addition, the release of Confidential RR-21 is likely to cause substantial harm to the competitive position of Rhode Island Energy. Confidential RR-21 includes sensitive information regarding the Company's procurement or future procurements of reclosers and the installation thereof. Disclosing this information to the public could harm the competitiveness of the Company's solicitations and any resulting contractual arrangements, which ultimately may harm customers. For example, if the cost comparisons in Confidential RR-21 were disclosed to the public, potential contractors could learn details of the Company's costs and bid to that number as opposed to a potentially lower bid. Such a scenario would raise costs for the Company and its customers.

III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of Confidential RR-21.

Respectfully submitted,

The Narragansett Electric Company
d/b/a Rhode Island Energy
By its attorney,

Andrew S. Marcaccio (#8168)
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

March 17, 2023

Record Request No. 1

Request:

Please provide the location(s) where any existing reclosers will be replaced with reclosers proposed in the FY 2024 budget. Please provide the date in service for the existing reclosers that will be replaced. Please also separate the response between those in the System Capacity and Performance category from those in the Grid Modernization category.

Response:

Please see the table below to show reclosers that will be replaced. These will all be part of the Grid Modernization category.

Feeder	Pole# and Street	Recloser Manuf.	Recloser Type	Control Type	Date In-Service	Location
108W61	36 FRONT WOONSOCKET	Cooper	WVE-27	Form 5	9/20/2000	Mainline
108W61	4 DARWIN (NORMAL) WOONSOCKET	Cooper	WVE-27	Form 5	9/20/2000	Mainline
13F2	58 SMITH ST. PROVIDENCE	Cooper	ME-RXE	Form 4C	6/12/2000	Mainline
155F6	342 MAIN ST. HOPKINTON	Cooper	WVE-27	Form 4C	5/20/2005	Mainline
21F1	172 PHENIX AVE. CRANSTON	Cooper	ME-RXE	Form 4C	7/3/2009	Mainline
3302	481 R.O.W. SOUTH OF BONNET SUB NARRAGANSETT	Cooper	WVE-38X	Form 5-LS	3/20/2003	Mainline
34F1	206 DANIELSON PIKE SCITUATE	Cooper	ME-RXE	Form 5	8/3/1993	Mainline
34F3	107 MOUNT HYGEA AVE. FOSTER	Cooper	UDP	Form 5	11/19/2007	Mainline
38F4	1 SERRAL SWEET JOHNSTON	Cooper	RXE	Form 4C	9/8/1998	Mainline
48F2	159 WATERMAN AVE. EAST PROVIDENCE	Cooper	ME-RXE	Form 4C	9/30/1998	Mainline
48F3	64 FORBES ST. EAST PROVIDENCE	Cooper	ME-RXE	Form 4C	11/29/1995	Mainline
48F4	229 PAWTUCKET AVE. EAST PROVIDENCE	Cooper	ME-RXE	Form 4C	11/29/1995	Mainline
51F3	2 BROAD COMMON RD. BRISTOL	Cooper	ME-RXE	Form 4C	9/3/1996	Mainline
61F4	2 J.P.MURPHY HIGHWAY WEST WARWICK	Cooper	ME-WVE	Form 4C	8/11/1998	Mainline
68F3	65 OLD POST CHARLESTOWN	Cooper	WVE-27	Form 4C	8/22/1993	Mainline
69F1	0776 R.O.W. BEHIND MANTON SUB. JOHNSTON	Cooper	RXE	Form 4C	3/6/2000	Mainline
84T3	476 R.O.W. NORTH OF BONNET SUB. NARRAGANSETT	Cooper	ME-RXE	Form 5-LS	3/20/2003	Mainline
87F1	3 METRO CENTER BLVD WARWICK	Cooper	WVE-27	Form 4C	9/27/1996	Mainline

Prepared by or under the supervision of: Kathy Castro

Record Request No. 2

Request:

Please provide the incremental benefits of each of the vintages of reclosers. For any incremental benefits dependent on grid modernization investments, please identify those separately.

Vintage Name	Incremental Functionality	Will be replaced	Will be integrated into GMP	Incremental Functionality dependent upon GMP integration

Response:

Please see response to RR-1 for the list of reclosers that will be replaced in FY2024. All existing Form 4 and Form 5 reclosers are planned to be replaced during the entirety of the Grid Modernization Plan ("GMP").

Existing WE7 reclosers with Form 6 controls and Viper-S reclosers with Schweitzer controls will remain and be integrated into the GMP.

New grid modernization reclosers will be the Viper-ST model with Schweitzer control/relay.

Please see the table on the next page showing the attributes of each type of recloser.

Prepared by or under the supervision of: Kathy Castro

	Cooper KWVE277/RXE Recloser with Form 4 Control	Cooper KWVE277/RXE Recloser with Form 5 Control	Cooper WE7 Recloser with Form 6 Control	Viper-S Recloser with SEL control	Viper-ST recloser with SEL Control
Mechanism					
Integrated Control Power Transformer				x	x
Integrated Voltage Sensing				x	x
High Accuracy Integrated Voltage Sensing					x
3-phase tripping	x	x	x	x	x
1-phase tripping					x
Oil Interrupter	x*	x*	x		
Vaccum Interrupter	x*	x*		x	x
560A max rating	x	x	x		
800A max rating				x	x
Spring Actuated Mechanism	x	x	x		
Magnetic Acutated Mechanism				x	x
High Voltage Closing Solenoid	x	x	x		
Low Voltage Closing Solenoid	x**	x**	x**	x	x
Control					
Microprocessor Relays	x	x	x	x	x
SCADA Capable		x	x	x	x
Multi-use Control (Radial or Loop Scheme)				x	x
Over/Under Voltage Protection Capable		x	x	x	x
Multiple Protection Profiles		x	x	x	x
Provides Oscillography		x	x	x	x
Power Metering		x	x	x	x
Voltage Metering		x	x	x	x
Fault locating			x	x	x
Sync Check			x	x	x
Directional Protection			x	x	x
Predictive Failure					x
Arc Detection Logic				x	x
ADMS Compatability and Advanced Programming***			x	x	x
Adaptive protection programming***				x	x

Notes:
*Oil with RXE Mechansim. Vacuum with KWVE277 Mechanism.
**High Voltage closing is standard. Low voltage closing accessory available.
***Dependent on ADMS.

Prepared by or under the supervision of: Kathy Castro

Record Request No. 3

Request:

Please provide the preliminary 2022 SAIDI and SAIFI using the IEEE definition and separately, the PUC regulatory definition.

Response:

See below for the Rhode Island Energy 2022 preliminary Year End Reliability Summary:

	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI (min)	CAIDI (min)
PUC	2,537	433,722	31,300,640	500,974	0.866	62.48	72.17
IEEE	3211	404,546	31,369,554	500,974	0.808	62.62	77.54

Prepared by or under the supervision of: Kathy Castro

Record Request No. 4

Request:

Withdrawn

Response:

The Commission has withdrawn this record request.

Record Request No. 5

Request:

Please provide any studies or analysis on the financial impact of the change in the capitalization policy on expenses from now until the next base rate case. (If the Company has not done one, this question is not asking them to perform one). If the analysis / studies have been done, please summarize the financial impact on expenses on an annual basis through the next base rate case. In other words, how much will annual expense change annually as a result of the change in capitalization policy?

Response:

The Company has not performed any studies or analysis regarding the financial impact of the potential changes in capitalization policies on expenses from now until the next rate case.

Record Request No. 6

Request:

With respect to the capitalization policy, please provide a listing of the O&M expenses that would be affected by the policy change.

Response:

The Company is in the early stages of the capitalization policy review process and has not yet determined which items will change. However, as described in the joint pre-filed direct testimony of Witnesses Briggs, Oliveira, Elmore and Hawk, beginning on Page 17, the Company has broken down the review into three main types:

1) Retirement unit catalog – this includes the majority of the electric and gas distribution item purchases. At this time, the Company does not anticipate much change to the Company's current capitalization thresholds for electric and gas distribution units, including meters and transformers.

2) General Property – such as small tools and equipment. The Company anticipates proposing to use a common threshold for capitalizing general property purchases. If the decision is made to use PPL's current thresholds for capitalization, general property purchases for electric would be capitalized above $500 whereas the Company's current threshold for capitalizing general property purchases is $2,500. For general property purchases for gas, the current threshold used by both the Company and PPL is $500 so the Company does not anticipate an impact at this time.

3) Software – At this time, the Company anticipates proposing to utilize PPL's capitalization threshold of $50,000 for software purchases. The Company's current threshold for capitalizing software purchases is $250,000.

Prepared by or under the supervision of: Stephanie Briggs

Record Request No. 7

Request:

Is the Company expecting to make a regulatory filing regarding the change to the capitalization policy (timing and type of filing)? If so, what process does the Company expect to follow? If not, why not?

Response:

During the Division of Public Utilities and Carriers ("Division") proceeding regarding PPL,[1] National Grid USA ("National Grid"), and the Company's petition requesting authorization to transfer ownership of the Company from National Grid to PPL, PPL agreed as follows:

> PPL agrees that, at least 12 months before Narragansett files its next distribution base rate case, PPL will provide to the Division key accounting policies that address the procedures that establish how costs are developed, booked and reported in customer revenue requirements, including but not limited to its capitalization policy describing its policies regarding capitalizing expenditures for all plant, property and equipment used for regulatory reporting purposes, allocation of affiliate costs to customers.[2]

This commitment was adopted by the Division as a condition attendant to the Division's approval of the transfer of ownership of the Company to PPL.

For purposes of this response, PPL's current assumption is that it will provide any change to the capitalization policy as a compliance filing to the Division by November 30, 2024, based on the Company's current assumption that it will file its next base distribution rate case around November 30, 2025. Concurrently, the Company will submit a copy of this filing to the Public Utilities Commission ("Commission") as an informational filing. The timing of this filing is consistent with PPL's commitment, which was incorporated into Division Order No. 24322 at page 250, that the Company will not file a base rate case seeking an increase in base distribution rates for gas and/or electric service sooner than three years from the date that PPL Rhode Island Holdings, LLC closed on its acquisition of the Company from National Grid, which occurred on May 25, 2022. This timing also is consistent with PPL's stay out commitment in its Settlement Agreement with Peter Neronha, the Attorney General for the State of Rhode Island dated May 19, 2022, that the Company will not file for a change in base distribution rates unless and until

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[11] PPL Corporation and PPL Rhode Island Holdings, LLC are referred to collectively as "PPL."
[2] *See* Division Report and Order No. 24322, Docket No. D-21-09 (issued February 23, 2022) ("Division Order No. 24322"), at 252.

Record Request No. 7, page 2

there is at least 12 months of operating experience under PPL's exclusive leadership and after the Transition Services Agreement ("TSA") with National Grid USA Service Company, Inc. terminates. The Company expects that the Commission will review the capitalization policy to the extent it impacts any future rate filings as part of its review of those filings. This timeline assumption for filing any change to the capitalization policy and filing the Company's next base distribution rate case is based on current TSA schedules and will be subject to change if warranted. The Company is not subject to any regulatory requirements to make any separate filings to obtain independent specific approval of its capitalization policy.

Prepared by or under the supervision of: Stephanie Briggs

Record Request No. 8

Request:

Referencing the Table in PUC 3-1, please break down those costs and then break down the costs allocated between Dyer and South Street. In other words, please provide a breakdown of the $1.9M, line by line, and show how the Company arrived at the $855k with details behind each line item.

Response:

$1.98 million is the Dyer Street Substation project capital spend (Funding Project numbers C051205 and C051211) through February 2020; the date at which the project at the original location was paused. The Company estimates that $0.855 million of the $1.98 million is associated with the DC Building.

The table below provides a breakdown of the cost incurred in connection with preparing and designing the substation before the project was paused. The table also shows cost category, purpose of cost, method of cost allocation, and amount.

Record Request No. 8, page 2

Cost Category/Vendor	Purpose of Cost Component	Cost Allocation Method	Dyer Street Location Alternative	South Street Location Alternative	Total
Labor & Benefits					
Labor - Mgt	Project development, permitting and licenses	Square footage	72,079	81,464	153,543
Labor - Union	Project development, permitting and licenses	Square footage	7,845	8,866	16,711
Variable Pay	Project development, permitting and licenses	Square footage	11,947	13,502	25,449
Gain Sharing	Project development, permitting and licenses	Square footage	192	217	408
Time not worked	Project development, permitting and licenses	Square footage	13,150	14,862	28,011
401k	Project development, permitting and licenses	Square footage	5,035	5,691	10,726
FAS112	Project development, permitting and licenses	Square footage	107	120	227
Group Life	Project development, permitting and licenses	Square footage	935	1,056	1,991
Healthcare	Project development, permitting and licenses	Square footage	11,567	13,073	24,640
OPEB	Project development, permitting and licenses	Square footage	2,218	2,507	4,724
Payroll taxes	Project development, permitting and licenses	Square footage	7,743	8,751	16,494
Pensions	Project development, permitting and licenses	Square footage	9,021	10,195	19,216
Workers Comp	Project development, permitting and licenses	Square footage	851	961	1,812
Consultants & Contractors					
Coneco Eng & Scientists	Environmental consultant	100% DC building refurbishment	142,329		142,329
Odeh Engineers	Civil and structural engineering	100% DC building refurbishment	230,846		230,846
BSC GROUP INC	Permitting and licenses	Square footage	14,360	16,229	30,589
CLEAN HARBORS ENV	Permitting and licensing contractor	Square footage	806	911	1,717
GZA GEOENVIRONMENTAL	Civil and structural engineering	Square footage	17,482	19,758	37,240
Pontoon	Project development and design contractor	Square footage	15,604	17,635	33,239
Public Archeology	Permitting and licenses - historical	100% DC building refurbishment	3,598		3,598
Robinson & Cole	Permitting and licenses	100% DC building refurbishment	50,395		50,395
Tauper Land Survey	Project development and design	Square footage	4,522	5,111	9,634
Vanasse Hangen Brustlin	Permitting and licenses	Square footage	5,511	6,229	11,740
Other	Miscellaneous	Square footage	919	1,039	1,958
AP discounts	AP discounts	various	(7,890)	(277)	(8,167)
Niagara Transformer Corp	Transformer payments	100% AC building & Site		418,649	418,649
Eagle Leasing/United Rentals	Equipment rental	Square footage	1,053	1,190	2,242
Transportation	Fleet pricing	Square footage	3,300	3,730	7,030
Employee Expenses	Employee Expenses	Square footage	1,670	1,888	3,558
Overheads	Overheads	Capital Spending	108,279	112,937	221,216
Capitalized Interest	Capitalized interest	Capital Spending	49,752	51,892	101,644
Other - PS&I	Preliminary survery & investigation	Capital Spending	65,103	67,904	133,007
Other - PS&I	Preliminary survery & investigation	Capital Spending	3,504	3,655	7,159
Other - PS&I	Preliminary survery & investigation	Capital Spending	869	907	1,776
Other - PS&I	Preliminary survery & investigation	Capital Spending	525	547	1,072
					-
FP C051211 - Dyer St Substation D Line		100% AC building & Site		234,032	234,032
			855,224	**1,125,231**	**1,980,455**

Record Request No. 8, page 3

Costs assigned to the Dyer Street Alternative were identifiable as being only associated with the refurbishment of the DC building and represent the DC building write-off.

A square footage allocator was used to assign costs that cannot be specifically attributed to either the Dyer Street Alternative or the South Street Alternative. The team believed that the square footage allocation best represents the relative portion of the DC building scope. It is based on the square footage of the Dyer Street DC building as compared to the total project, at the original location.

A second allocator, titled Capital Spending was used to apportion overheads, capitalized interest, and preliminary survey and investigation costs; this allocator apportions the actuals based on capital spend. The team concluded this allocator best represents how these items get charged to the work request and is the appropriate one to use.

Once the entire project is complete, the Company will again review all costs to ensure spending related to the refurbishment of the DC building is not included in ISR rate base and revenue requirements. For the 2023 ISR, the Company will exclude $0.855 million shown on the table above from rate base and revenue requirements.

Prepared by or under the supervision of: Daniel Glenning

Record Request No. 10

Request:

Please provide the average number of major event days between 2012 through 2021.

Response:

The average number of major event days per year from 2012 to 2021 is 4 days. Please see the following detailed table.

Year	**Number of Major Event Days**
2012	**4**
2013	**3**
2014	**0**
2015	**1**
2016	**4**
2017	**4**
2018	**6**
2019	**6**
2020	**6**
2021	**4**
Average	**4**

Prepared by or under the supervision of: Kathy Castro

Record Request No. 11

Request:

Does the major event day definition translate into storm fund categorization? If not, how are the definitions different?

Response:

A Major Event Day does not always translate into storm fund categorization. A Major Event Day is determined by reliability data. A major storm event for storm fund categorization is determined by the amount of incremental operation and maintenance ("O&M") costs the Company incurred to prepare for, and respond to, a qualifying storm event.

As described in the 2021 Service Quality Report (Electric Operations) filed with the Public Utilities Commission in Docket No. 3628, Major Event Days represent those few days during the year on which the energy delivery system experienced stresses beyond those normally expected, such as severe weather. A day is considered a Major Event Day if the daily SAIDI calculation exceeds the specified threshold. This threshold is calculated on an annual basis.

The Company is authorized to charge the incremental O&M costs of a storm to the Storm Contingency Fund when the Company incurs incremental O&M storm-related costs above the applicable dollar threshold amount for the calendar year in which the storm occurred. The applicable storm fund threshold amount for calendar year 2022 was $1.201 million as noted in the Annual Storm Fund Report for Calendar Year 2021 filed in Docket No. 2509 – Storm Contingency Fund.

Record Request No. 12

Request:

Referencing Bates page 123 of Book 1, Attachment 4, Chart 4, please update the table to add what TMED was.

Response:

Please see the updated Chart 4:

	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	CY21
SAIFI-Target 1.05	0.90	0.72	0.78	0.94	0.97	0.78	1.00	1.02	0.95	0.95
SAIDI- Target 71.9	66.00	57.30	54.06	64.30	69.13	59.10	65.11	68.20	69.11	68.80
# Major Event Days	4	3	0	1	4	4	6	6	6	4
Total Customer Interrupted on Major Event Days	201,709	268,925	7,287	141,046	114,772	203,211	282,481	177,296	352,939	240,195
Tmed	4.97	5.74	5.64	5.48	5.26	4.58	4.49	5.05	6.03	6.67

Note: CY16 has a 24 hour continuous case exclusion

Prepared by or under the supervision of: Kathy Castro

Record Request No. 13

Request:

How many reclosers have been "locked down" within the 80% reference? Please provide the production schedule and the delivery schedule with the amounts provided in each delivery.

Response:

The Company has locked down production for approximately 300 reclosers, equating to approximately 77% of total planned recloser installations for both the Mainline Recloser Enhancement and Advanced Recloser program. Previous responses related to recloser purchases (DIV 2-10 and PUC 1-10) only referred to the Mainline Recloser Enhancement program.

The delivery schedule is as follows:

Month	# of Reclosers to be Delivered
April	52
May	78
June	60
July	60
Oct	50

Prepared by or under the supervision of: Daniel Glenning

Record Request No. 14

Request:

What would the "customer interruptions avoided" from the 22 reclosers be using the regulatory measure?

Response:

The "customer interruptions avoided" from the 22 reclosers, using the regulatory measure, is 3,816. The table below sets forth the details of each event in which the reclosers resulted in "customer interruptions avoided." Five of the seven events did not result in "customer interruptions avoided" using the regulatory measure because the events resulted in interruptions greater than 1 minute, but less than 5 minutes.

Date	Feeder	Cause	Type	Customer Interruptions Avoided (PUC)	Customer Interruptions Avoided (IEEE)
12/7/2022	85T1/86F1	Failed Sleeve P60 Dunns Corner, Westerly	Tie PTR	0	1739
1/5/2023	126W51	MVA P205-33 Old River Rd, Lincoln	Tie PTR	0	678
1/22/2023	72F5	Tree at P60 W.Shore Rd, Warwick	Midline PTR	2091	2091
1/27/2023	1201W5	MVA P4-1 Columbus Ave, Pawtucket	Tie PTR	1725	1725
2/9/2023	126W41	Crew working on site lost phase	Tie PTR	0	1950
2/14/2023	102W52	MVA P19 Hunt St, Central Falls	Tie PTR	0	1110
2/24/2023	68F3	Tree at P55 S.County Trail	Tie PTR	0	1011

Prepared by or under the supervision of: Kathy Castro

Record Request No. 15

Request:

(a) Please provide 2021 SAIDI and SAIFI maps similar to those provided in Docket No. 5209. To the extent this response cannot be presented exactly as in Docket No 5209 as a result of the transition, please explain and provide what is possible within the timeframe allowed.

(b) Please provide a similar map as provided in subsection (a) for purposes of illustrating where the proposed 100 mainline reclosers will be deployed.

Response:

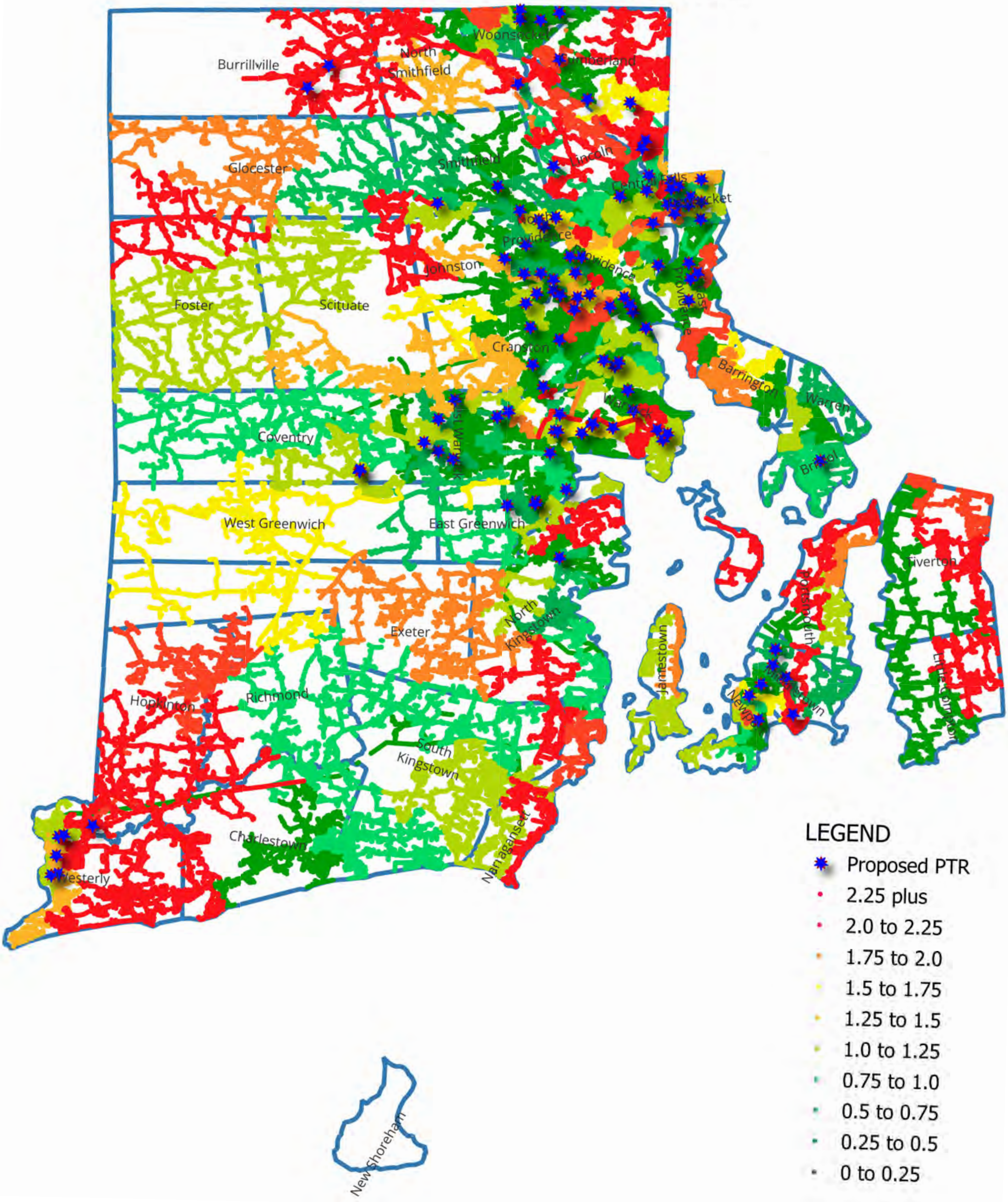
Please see:

- Attachment RR-15-1 for a map of 2021 SAIFI by Feeder without Major Storms;
- Attachment RR-15-2 for a map of 2021 SAIDI by Feeder without Major Storms;
- Attachment RR-15-3 for a map of 2021 SAIFI by Feeder with Major Storms; and
- Attachment RR-15-4 for a map of 2021 SAIDI by Feeder with Major Storms.

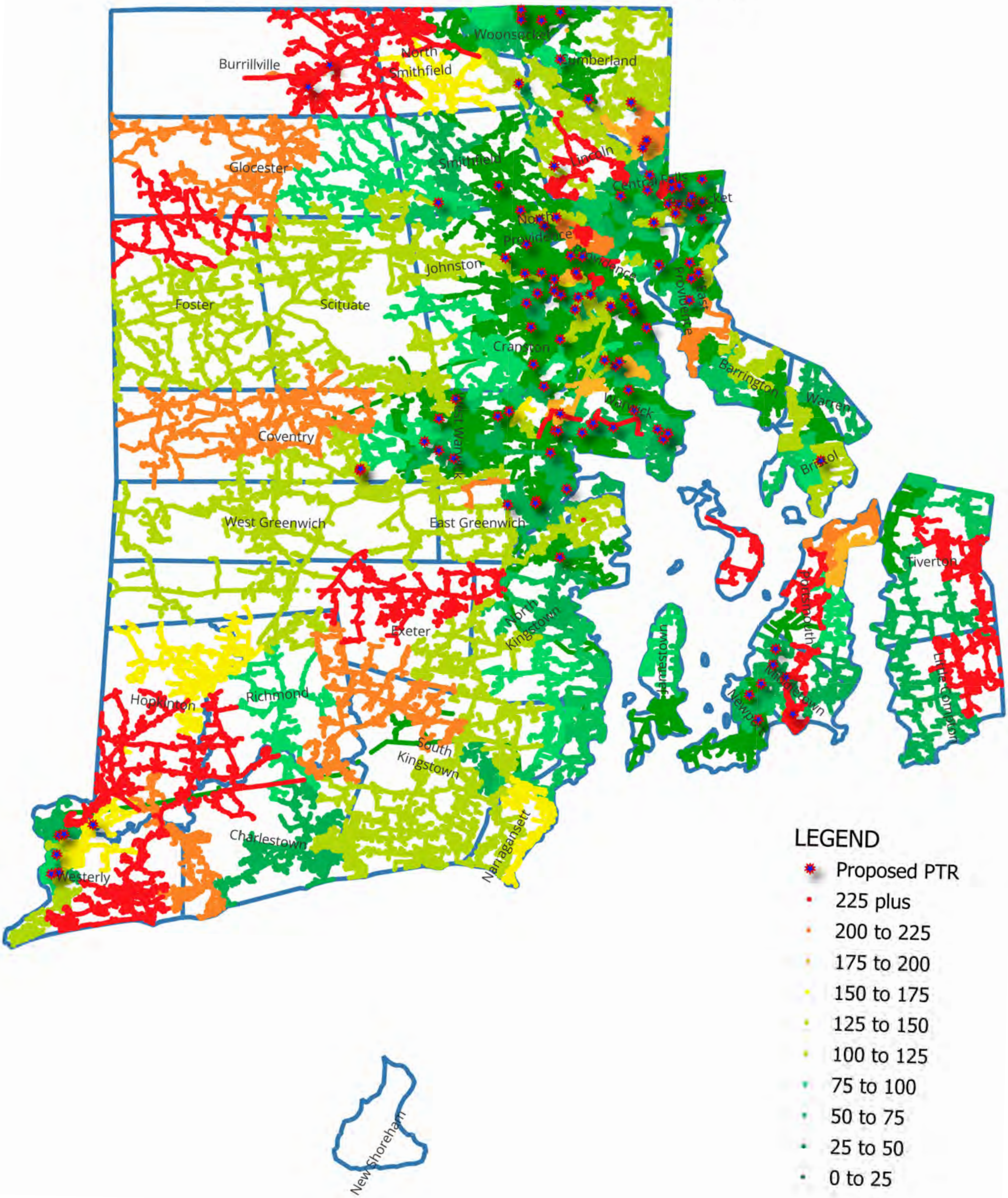
Attachment RR-15-1 and RR-15-2 identify the locations for the 100 proposed mainline reclosers. Those locations are identified on the Legend as "Proposed PTR."

Prepared by or under the supervision of: Kathy Castro

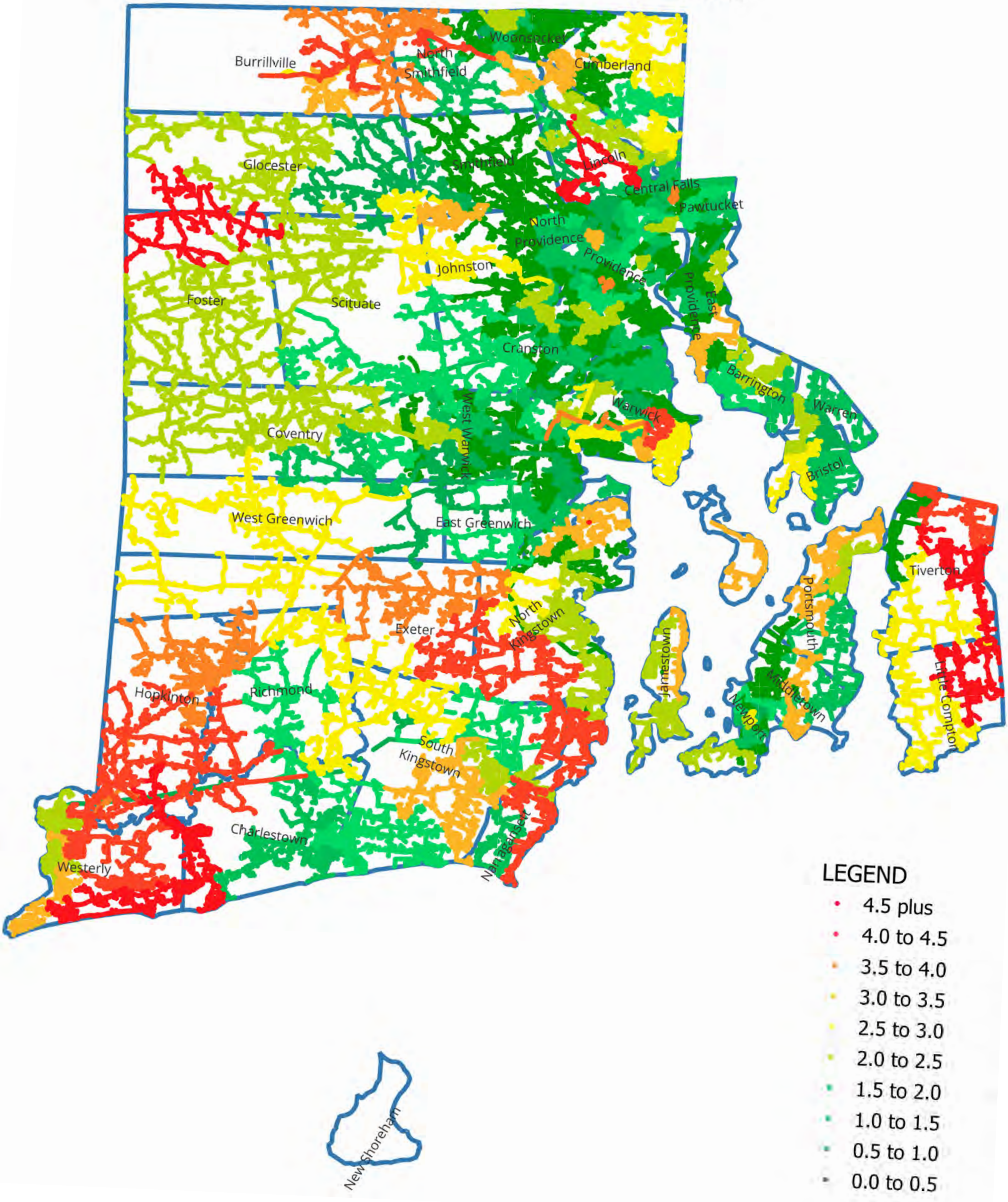
Narragansett Electric 2021
SAIFI - By Feeder - Without Major Storms



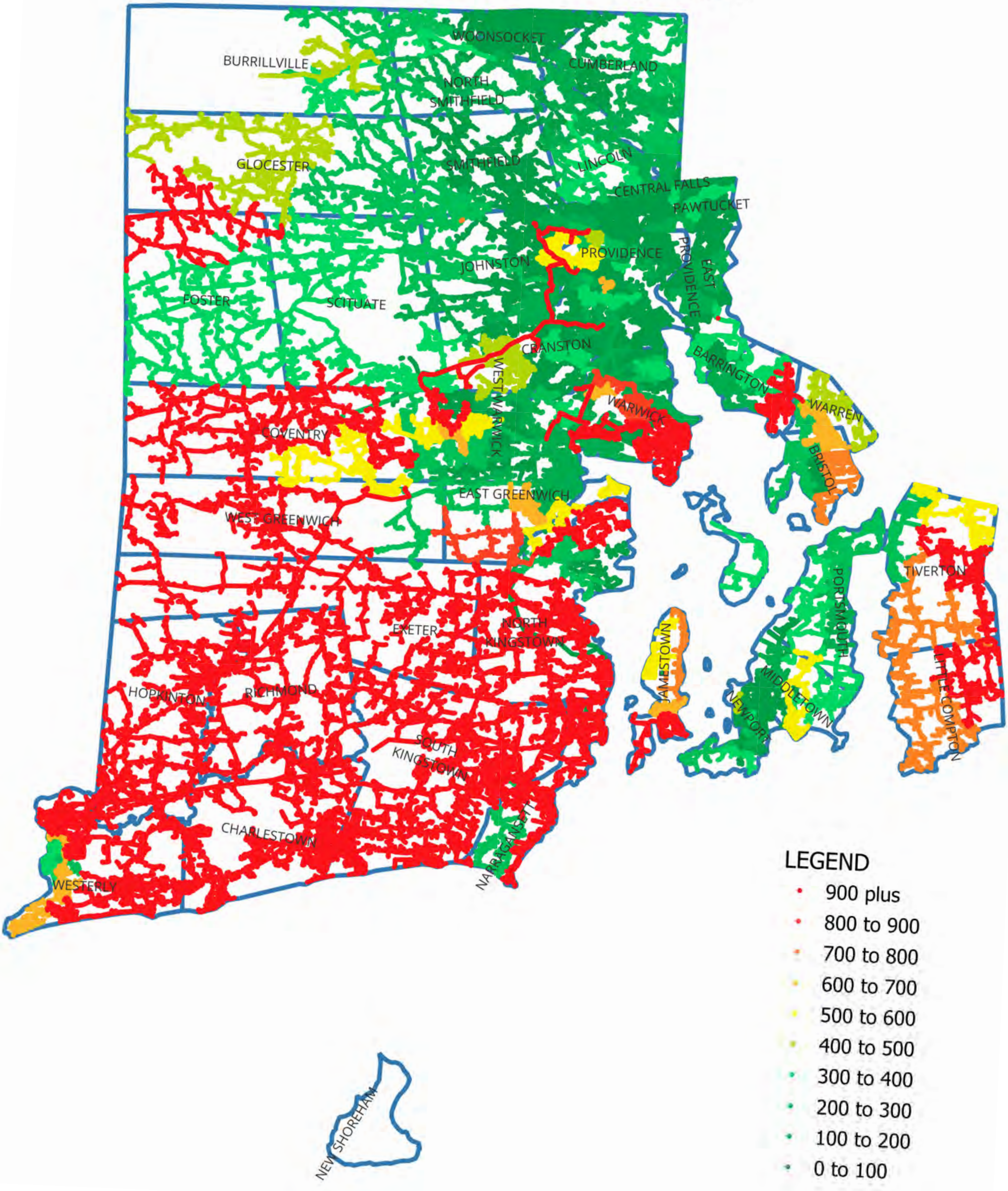
Narragansett Electric 2021
SAIDI - By Feeder - Without Major Storms



Narragansett Electric 2021
SAIFI - By Feeder - With Major Storms



Narragansett Electric 2021
SAIDI - By Feeder - With Major Storms



Record Request No. 16

Request:

In addition to the 22 reclosers, are there any other investments made in FY 2023 that were not included in the FY 2023 plan, but the Company expects to include in the FY 2023 reconciliation? If so, please identify them.

Response:

Although the 22 reclosers were not identified specifically in the FY 2023 Plan, they were initiated and progressed under the reliability blanket line item under the System Capacity & Performance Spending Rationale.

The table below identifies other investments that were not identified specifically in the FY 2023 Plan, but that the Company progressed and expects to include in the FY 2023 reconciliation:

Project Name	**Spending Rationale**	**Explanation**
Animal Fences	System Capacity & Performance	10 substations identified needing animal fences. This is in the "Other" line item in Attachment 3.
South St Fencing	Asset Condition	Fencing work to be done with the completion of the Dyer St project. This will be completed under the South St funding project and in the "Other" line item in Attachment 3.
115F8 Inst Regs & Smart Caps	System Capacity & Performance	Work to address low voltage issues. This is in the "Other" line item in Attachment 3.
COVID Spending	System Capacity & Performance	Unexpected carryover from FY22 approved plan. This is in the "Other" line item in Attachment 3.
VVO	System Capacity & Performance	Unexpected carryover from FY22 approved plan. This is a separate line item in Attachment 3.

Prepared by or under the supervision of: Nicole Begnal

Record Request No. 16, page 2

Project Name	**Spending Rationale**	**Explanation**
Strategic DER	Customer Request/Public Requirements	Unexpected carryover from FY22 approved plan. This is in "Regulatory Requirement" in Attachment 3.
Nasonville Rebuild	Damage Failure	Damage failure work from bus fault. This is a separate line item in Attachment 3.
Mainline Recloser Enhancements	System Capacity & Performance	Engineering, design, and procurement for FY 2024 recloser installations. This is a separate line item in Attachment 3.

Prepared by or under the supervision of: Nicole Begnal

Record Request No. 17

Request:

Please provide an explanation of the sanctioning process and delegation of authority, providing templates where available.

Response:

The Delegation of Authority ("DoA") levels are as follows:

Job Code	RI Energy DOA	Authorization
Supervisors	$50,000	Up to
Managers	$1,000,000	Up to
Directors / Sr. Manager	$10,000,000	Up to
Vice President / Sr. Director	$30,000,000	Up to
COO / SVP / President	$40,000,000	Up to
Leadership Committee	$40,000,000	Above

Please see Attachment RR-17-1 for a fact sheet template and Attachment RR-17-2 for a sanction paper template. The documentation and approvals required for the sanction process depend on the cost of a project:

Total Project Estimate:	Documentation:	Process:
Up to $5 million	Fact Sheet	Fact sheet to be included in Power Plan when routed for DoA.
Between $5 and $40 million	Sanction Paper	Project Author/Sponsor is required to consult and gain approval of the applicable supporters prior to routing for DoA in Power Plan.

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

Record Request No. 17, page 2

Total Project Estimate:	**Documentation:**	**Process:**
Above $40 million	Sanction Paper	Project Sponsor is required to consult and gain approval of the applicable supporters and Leadership Committee, prior to routing for DoA in Power Plan.

The Company's SharePoint site will be used for the review process and as a repository.
A project will require re-sanctioning if it exceeds estimate accuracy. The project sponsor will be responsible for documenting lessons learned and following appropriate guidelines to financially close the project.

Fact Sheet (FS)

Project Title – Location

Distribution Related Project Number(s):	*PP Project #s*
Substation(s) / Feeder(s) Impacted:	
Voltage(s):	
Geographic Area Served:	
Summary of Issues:	*Provide justification and need including benefits (optional: reference Docket 4600 if applicable) and consequences of not completing the project. Identify whether it is Discretionary vs. Non-Discretionary. Specify whether it is Customer Driven.*
Recommended Plan	
Alternative Plans	
Long Range Plan Alignment	*Aligned/reinforces/revisions required to Area Study or Grid Mod recommendations.*
Planned Capital Spend ($000)	(see table below)

Spend Type	Prior Years ($M)	CY - 2023	CY - 2024	CY - 2025	CY - 2026	CY - 2027	CY - 2028+	Total
CAPEX								
OPEX								
REMOVAL								
TOTAL								

Sanction Paper (SP)

Title:	Project Name	**Version**	V [1.0]
Project #:	PP Project #s	**Sanction Type:**	Choose an item.
Utility Service:	Choose an item.	**Date of Request:**	02/08/2017
Author:	Project Author	**Sponsor:**	Department Head
Project/Program Manager:			

1 Project Overview

Summary of Driver
Project Scope (Preferred Alternative)
Cost Summary

[Text]

2 Project Driver

Provide justification and need including benefits (optional: reference Docket 4600 if applicable) and consequences of not completing the project. Identify whether it is Discretionary vs. Non-Discretionary. Specify whether it is Customer Driven.

[Text]

3 Project Scope (Preferred Alternative)

[Text]

4 Project Alternative Review

[Text]

5 Other

Include any unique aspects of the project within this section for example, associated projects (e.g. DG, Grid Mod Plan, other specific projects or programs), project risks, ROW citing & Regulatory filing requirements, traffic management, environmental requirements, etc.

[Text]

6 Cost Summary

Author should consult with Project or Program Manager, Construction Management and Portfolio Manager (Nicole Begnal) to develop optimal cash flow that aligns with the comprehensive spending plan. Discussions should inform whether there are known schedule constraints (outage windows, adjacent projects, resource limitations, etc.) that will better inform cash flow.

Project #	Title	Estimate Accuracy	Spend Type	Prior Years ($M)	CY - 2023	CY - 2024	CY - 2025	CY - 2026	CY - 2027	CY - 2028+	Total
		(+/- 25%)	CAPEX								
			OPEX								
			REMOVAL								
			TOTAL								

Total Project Sanction	CAPEX								
	OPEX								
	REMOVAL								

Use following table if CIAC if applicable.

Project #	Title	Estimate Accuracy	Spend Type	Prior Years ($M)	CY - 2023	CY - 2024	CY - 2025	CY - 2026	CY - 2027	CY - 2028+	Total
		(+/- 25%)	CAPEX								
			OPEX								
			REMOVAL								
			TOTAL								

Total Project Sanction	CAPEX								
	OPEX								
	REMOVAL								
	CIAC	($)	($)	($)	($)	($)	($)	($)	($)
	Total								

7 Supporters

Project Author is required to consult and gain approval of the applicable supporters, prior to routing for DoA in Power Plan.

Department	Yes	N/A
Portfolio/ISR Management	☐	☐
Resource Planning	☐	☐
Project Management	☐	☐
Asset Management/Planning	☐	☐
Portfolio/ISR Management	☐	☐
Resource Planning	☐	☐
Project Management	☐	☐
Substation Engineering and Design	☐	☐
Protection Engineering	☐	☐
Distribution Design	☐	☐
Transmission Line Design	☐	☐
Control Center	☐	☐
Operations	☐	☐
Finance	☐	☐
Regulatory	☐	☐

8 Appendices

Available one-lines, studies, references.

Record Request No. 19

Request:

Please provide the pre-filing fact sheets/summaries provided to the Division in pre-filing documents.

Response:

Please see Attachment RR-19-1 through Attachment RR-19-32 for the fact sheets provided in the Electric ISR Pre-Filing Planning Information submitted to the Rhode Island Division of Public Utilities & Carriers on September 9, 2022. Fact sheets were provided in response to Recommendation #9 and #10 and for any new project introduced in the fiscal year ("FY") 2024 Plan. Please note, at the time these were submitted, the Company used FY 2023 to refer to April 1, 2023 – December 31, 2023.

Response to Recommendation	Project	Spending Rationale	Attachment #
9	Apponaug Long Term Plan	Asset Condition	RR-19-1
9	Centerdale Substation	Asset Condition	RR-19-2
9	Phillipsdale Substation	Asset Condition	RR-19-3
9	Tiverton Substation	Asset Condition	RR-19-4
9	Central RI West D-Line Asset Condition Issues	Asset Condition	RR-19-5
9	Central RI West Equipment Replacement	Asset Condition	RR-19-6
10	Mainline Recloser Enhancements	System Capacity & Performance	RR-19-7
10	Nasonville Substation	System Capacity & Performance	RR-19-8
10	Staples Substation Reliability Improvements	System Capacity & Performance	RR-19-9
10	Tiverton Distribution Line	System Capacity & Performance	RR-19-10
10	Weaver Hill Substation	System Capacity & Performance	RR-19-11
Supplemental Information	Other Area Study Projects – Central RI West	System Capacity & Performance	RR-19-12

Prepared by or under the supervision of: Nicole Begnal

Record Request No. 19, page 2

Response to Recommendation	Project	Spending Rationale	Attachment #
Supplemental Information	Other Area Study Projects – System Capacity & Performance – East Bay	System Capacity & Performance	RR-19-13
Supplemental Information	Other Area Study Projects – Newport	System Capacity & Performance	RR-19-14
Supplemental Information	Other Area Study Projects – Northwest Rhode Island	System Capacity & Performance	RR-19-15
Supplemental Information	Other Area Study Projects – System Capacity & Performance - South County West	System Capacity & Performance	RR-19-16
Supplemental Information	Nasonville Damage/Failure Rebuild	Damage / Failure	RR-19-17
Supplemental Information	Blackstone Valley South 4kV Substation Retirements	Asset Condition	RR-19-18
Supplemental Information	Other Area Study Projects – Asset Condition – Blackstone Valley South	Asset Condition	RR-19-19
Supplemental Information	Other Area Study Projects - East Bay Substation Retirements	Asset Condition	RR-19-20
Supplemental Information	Other Area Study Projects – Newport	Asset Condition	RR-19-21
Supplemental Information	Other Area Study Projects - Northwest Rhode Island	Asset Condition	RR-19-22
Supplemental Information	Other Area Study Projects – Providence	Asset Condition	RR-19-23
Supplemental Information	Other Area Study Projects – South County West	Asset Condition	RR-19-24
Supplemental Information	Advanced Distribution Monitoring System (ADMS)	Grid Modernization	RR-19-25
Supplemental Information	Advanced Reclosers	Grid Modernization	RR-19-26

Prepared by or under the supervision of: Nicole Begnal

Record Request No. 19, page 3

Response to Recommendation	Project	Spending Rationale	Attachment #
Supplemental Information	DER Monitor Managed	Grid Modernization	RR-19-27
Supplemental Information	Electromechanical Relay Upgrades	Grid Modernization	RR-19-28
Supplemental Information	Fiber	Grid Modernization	RR-19-29
Supplemental Information	IT Infrastructure	Grid Modernization	RR-19-30
Supplemental Information	Mobile Dispatch	Grid Modernization	RR-19-31
Supplemental Information	Smart Capacitors & Regulators	Grid Modernization	RR-19-32

Prepared by or under the supervision of: Nicole Begnal

Attachment # RR-19-1
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 short circuit current exceeds the breaker duty on the 23 kV 1-4 breaker. In addition, all the 23 kV breakers are in poor condition and no longer reliable. • The #4 transformer has signs of increased gassing placing it at an elevated risk of failure. • 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).
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. 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 2023 (9 months)**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**
	763	1,428	1,096	255	16

Attachment # RR-19-2
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
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.
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 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
1,116	1,750	2,543	1,302	540

Attachment # RR-19-3
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 and has been identified for replacement in the ARP. Replacement of the T2 transformer has been deferred pending completion of this study. • 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. • The transformer and bus arrestors are obsolete. • A timed scheme at the station prevents bus ties from occurring unless disabled. This scheme is complex to operate The Phillipsdale 23/12.47kV substation consists of non-standard equipment and construction. The following concerns exist at this station: • A single LTC transformer supplies two 12.47kV feeders with pole mounted line reclosers. 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.

<table>
<tr><td></td><td>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 congested public roadways.</td></tr>
<tr><td>Recommended Plan</td><td>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.</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>East Bay Area Study completed August 2015</td></tr>
<tr><td>Planned Capital Spend
($000)</td><td><table><tr><th>FY 2023 (9 months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr><tr><td>2,390</td><td>2,951</td><td>4,201</td><td>4,440</td><td>2,090</td></tr></table></td></tr>
</table>

Attachment # RR-19-4
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: • Equipment throughout the station does not meet the required clearances • 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 33F1, 33F2 and 33F4 voltage regulators are nearing the end of their design life cycle. The 33F3 voltage regulators were replaced in 2017 and are in excellent condition. • 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.
Recommended Plan	Add one 12.47kV circuit position on the No. 2 Bus (33F6) and replace all equipment with asset condition issues. This work consists of the installation of one (1) 12.47kV breaker, three (3) single-phase regulators, and a new getaway manhole and duct system inside of the Tiverton substation. 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.
Alternative Plans	See area study report for alternative plans.

Long Range Plan Alignment	Tiverton Area Study completed May 2021
Planned Capital Spend ($000)	

FY 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
85	341	688	786	491

Attachment # RR-19-5
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.
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 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
-	780	618	650	455

Attachment # RR-19-6
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.
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

<table>
<tr><td></td><td>
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
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 2023
(9 months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr>
<tr><td>-</td><td>5,602</td><td>4,433</td><td>4,666</td><td>3,267</td></tr>
</table>
</td></tr>
</table>

Attachment # RR-19-7
Mainline Recloser Enhancements

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	Rhode Island Substations and Feeders
Voltage(s):	4.16kV, 12.47kV, 13.8kV
Geographic Area Served:	All of RI Energy Territory
Summary of Issues:	There are approximately 100 4kV and 15 kV circuits having greater than one mile of OH line exposure and more than 100 customers that have zero reclosers. In addition, there are approximately 70 15kV circuits having greater than five miles of OH line exposure and more than 1,000 customers that have only one recloser. The absence of reclosers on these circuits increases the amount of customer outages due to the lack of sectionalization and reduces the ability to remotely transfer load during an outage.
Recommended Plan	Install reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts.
Long Range Plan Alignment	This effort will consider future feeder rearrangements proposed by area study recommendations to ensure recloser reliability value. All reclosers will use the latest control technology aligned with the pending Grid Modernization Plan.
Planned Capital Spend ($000)	see table below

FY 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
2,000	-	-	-	-

Attachment # RR-19-8
Nasonville Substation

Distribution Related Project Number(s):	C087770 Nasonville Sub (D-Sub) C087771 Nasonville Sub (D-Line)
Substation(s) / Feeder(s) Impacted:	Nasonville: 127W40, 127W41, 127W42, 127W43
Voltage(s):	13.8 kV
Geographic Area Served:	Burrillville, North Smithfield, Smithfield
Summary of Issues:	Nasonville is a single transformer 115/13.8kV substation that consists of four feeders. It is currently very difficult to offload the feeders due to minimal ties to feeders other than Nasonville. The 127W43 feeder is predicted to exceed the summer normal rating as well as load-at-risk criteria. Contingency loss of the the Nasonville T1 transformer exceeds load-at-risk criteria, and could result in approximately 13MVA (350 MWHr) of unserved load.
Recommended Plan	The recommended plan for the Nasonville Substation includes bringing a new 115kV OH supply line from Woonsocket substation to Nasonville substation and adding a second transformer and straight bus to the existing Nasonville substation. This option requires installation of a new 115kV radial line with two breaker bays at Woonsocket substation in order to bring a new 115kV line through the existing ROW which is about 6 miles long (new 115kV source). This plan also recommends replacing the existing 115kV protection on the existing Transformer (T1) with a circuit switcher at the Nasonville substation.
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 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
912	603	1,159	2,115	4,129

Attachment # RR-19-9
Staples Substation Reliability Improvements

<table>
<tr><td>Distribution Related Project Number(s):</td><td>BSVS012 Staples Reliability Improvements (D-Line)</td></tr>
<tr><td>Substation(s) / Feeder(s) Impacted:</td><td>Staples: 112W41, 112W43, 112W44</td></tr>
<tr><td>Voltage(s):</td><td>12.47kV</td></tr>
<tr><td>Geographic Area Served:</td><td>Cumberland, Woonsocket</td></tr>
<tr><td>Summary of Issues:</td><td>The Staples substation is a two transformer 115/12.47kV substation that consists of four feeders. Contingency loss of the 112W44 circuit exceeds load-at-risk criteria.
Additionally, three Staples feeders, 112W41, 112W43, and 112W44 have average reliability statistics in excess of system averages.</td></tr>
<tr><td>Recommended Plan</td><td>The recommended plan for the reliability and contingency concerns at the Staples substation is as follows:

Feeder 112W43:
Reconductor 1 mile of open wire construction to spacer cable construction. along West Wrentham Road from pole #35 to pole #82.
Based on the assessment of applicability of non-wires alternatives, the preferred solution may be a good candidate to go to market for an NWA solution. The NWA solution is currently being evaluated internally.
Feeder 112W44:
Reconductor approximately 1.3 miles of open wire construction to spacer cable construction along Diamond Hill Road from pole #300 Nate Whipple Hwy to pole #256 Diamond Hill Road and Fisher Road from pole #10 Wrentham Rd to pole #24 Fisher Rd.
Install a line extension between the 112W43 feeder and the 112W44 feeder of ~3,500 circuit feet of new 477 Al overhead conductor from Pole #219 to Pole #162 Pine Swamp Road.</td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans. Note that the work related to the 112W43 feeder will be subject to further review for non-wires alternatives prior to proceeding with the scope described above.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>Blackstone Valley South Area Study completed October 2021</td></tr>
<tr><td>Planned Capital Spend
($000)</td><td><table><tr><th>FY 2023 (9 months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr><tr><td>270</td><td>640</td><td>681</td><td>851</td><td>227</td></tr></table></td></tr>
</table>

Attachment # RR-19-10
Tiverton Distribution Line

Distribution Related Project Number(s):	TIV0002 Tiverton Sub (D-Line)
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 Westport (MA) to the east. Normal and contingency capacity concerns exist on the four feeders. The 33F1 feeder is predicted to exceed its normal rating and all four feeders exceed contingency load-at-risk criteria. Reliability concerns exist on the 33F3 and 33F4 due to bare open wire construction in the heavily treed areas of Little Compton.
Recommended Plan	The recommended plan for the Tiverton substation is to add one 12.47kV circuit position on the No. 2 Bus (33F6). This work consists of the installation of one (1) 12.47kV breaker, three (3) single-phase regulators, and a new getaway manhole and duct system inside of the Tiverton substation. The new feeder requires the installation of ~21,000 feet of 1000kcmil cable from the substation to 390 Brayton Road, Tiverton. This work is proposed to serve a pending DG project but will still be required should the project not move forward. The new 33F6 will be extended approximately 17,200 feet from the DG site to the intersection of Lake Road and East Road (Tiverton). Approximately 5,700 feet of existing 3-phase OH conductor (from P50 East Road to P3 East Road) will be reconductored with 477 AL to allow for a feeder tie with the 33F4. The 33F6 will be used to pick up load to alleviate the feeder loading and contingency load-at-risk issues.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Tiverton Area Study completed May 2021
Planned Capital Spend	

($000)	FY 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027	
	64	291	574	656	410	

Attachment # RR-19-11
Weaver Hill Substation

Distribution Related Project Number(s):	C088009 Weaver Hill; Rd SubT Extension (D-Line) C085412 Weaver Hill Rd Sub (D-Sub) C085414 Weaver Hill Rd Feeder Dline (D-Line)
Substation(s) / Feeder(s) Impacted:	Coventry: 54F1 Hopkins Hill: 63F6
Voltage(s):	12.47kV
Geographic Area Served:	West Greenwich, East Greenwich, Coventry, Exeter, West Warwick
Summary of Issues:	There is predicted summer normal overload concern on the Kent County 34.5 kV system. The Hopkins Hill 63F6 feeder and the Coventry 54F1 feeder are predicted to exceed their summer normal thermal rating.
Recommended Plan	Install a new substation on Weaver Hill Rd. This work includes: • Extend the 3309 and 3310 lines for 1.7 miles from Nooseneck Hill and Weaver Hill Roads in West Greenwich to a Rhode Island Energy owned property off P. 64 Weaver Hill Rd. • Install a 7.5/9.375 MVA transformer and one modular feeder position to be supplied by the 3309 preferred and 3310 alternate. • Install distribution line work for a new feeder to be made up of parts of Coventry 54F1 and Hopkins Hill 63F6.
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 2023 (9 months)	FY 2024	FY 2025	FY 2026	FY 2027
1,162	1,852	2,386	2,512	1,758

Attachment # RR-19-12

Other Area Study Projects – System Capacity & Performance - Central Rhode Island West

Distribution Related Project Number(s):	C088048 Coventry 54F1 Reconductoring (D-Line) C088061 2232 Industrial Dr. ERR (D-Line) C088062 2232 Panto Rd. ERR (D-Line) C088059 Kilvert 87F1 Line Extension (D-Line) C088057 Natick 29F1 Reconductoring (D-Line) C088058 New London 150F6 Reconductoring (D-Line)
Substation(s) / Feeder(s) Impacted:	Coventry: 54F1 Kilvert: 87F1 Natick: 29F1 New London: 150F6, 150F8 Warwick Mall: 28F1 Drumrock: 2232
Voltage(s):	12.47kV and 23kV
Geographic Area Served:	West Greenwich, East Greenwich, Coventry, Exeter, West Warwick
Summary of Issues:	The Coventry 54F1 circuit has experienced outage related issues due to tree contacts. The 4.5 miles along Route 117 from Victory Highway to Plainfield Pike in Coventry, RI has experienced a majority of these tree contacts. The 2232 feeder has asset and clearance issues There is lack of adequate backup feeder capacity to the Warwick Mall. The Natick 29F1 circuit has 1,000’ of 1/0 Cu conductor predicted to be overloaded along Providence St in West Warwick, RI. The New London 150F6 circuit has 425’ of 1/0 Al conductor predicted to be overloaded along Providence Street in West Warwick, RI.
Recommended Plan	The recommended plan to resolve the reliability issues on 54F1 is to reconductor the 4.5 miles along Route 117 from Victory Highway to Plainfield Pike with 477 Al SPCR. The recommended plan for the 2232 line is to relocate the line near Industrial Dr onto the street, overbuilding the 64F1 circuit. Remove ~1200’ of 3-4/0 AL conductor from P 9063 Industrial Dr, through the parking lot to P 9057 Flat River Rd. Remove poles 9061 and 9062 from the parking lot. Replace poles 9057, 208, 206, and 205 Flat River Rd with 45’ class 2 poles. Replace poles

	9063, 2, and 1 Industrial Dr with 45’ class2 poles. Install ~1200’ of 3-477 AL conductor from P9063 Industrial Dr, to P9057 Flat River Rd. Replace poles 9166, 9167, 9168, 9169, 9170, 9171, 9172, 9173, 9174, 9175, 9176, and 9178 on Panto Rd with 45’ class 2 poles. Reconductor the 2232 line from pole 9165 to pole 9178 with 3-477 AL (~1900’). Remove parallel 2/0 CU conductor. Replace associated equipment as needed. The recommended solution for the lack of adequate backup feeder capacity at the Warwick Mall is to create a new feeder tie by tapping the existing Kilvert St 87F1 feeder on Greenwich Ave. in Warwick, RI. The requires installing a new pole top recloser and approximately 700’ of 2 way duct bank with 1000 Cu underground cable to pick up the existing Warwick Mall 28F1 load. The recommended plan for Natick 29F1 is to reconductor the 1,000’ section along Providence Street in West Warwick, RI with 477 Al SPCR. The recommended plan for New London 150F6 is to reconductor the 425’ section along Providence Street in West Warwick, RI with 477 Al SPCR.
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)	(see table below)

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
1,372	757	1,198	1,261	883

Attachment # RR-19-13
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 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
-	63	305	378	95

Attachment # RR-19-14
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) NWPT011 Kingston (D-Line) NWPT012 Dexter 36W42 (D-Line) NWPT013 Newport 203W1 (D-Line) NWPT015 37K22 and 37K33 Reconfiguration (D-Line)
Substation(s) / Feeder(s) Impacted:	Newport: 203W1, 203W5 Gate 2: 38K23 Eldred: 45J4 Kingston: 131J6, 131J12 Dexter: 36W42 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 203W1 and 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. Kingston is a two transformer 23/4.16kV substation that consists of five feeders. Kington also acts as a 23kV switching station for the area. There are contingency concerns on the 38K21 and normal loading concerns on the 131J12. Dexter 13.8kV station is a one transformer 115/13.8kV substation that consists of four feeders. The 36W42 feeder has load unbalance issues. Jepson 23kV substation is a two transformer 115/23kV substation that consists of four feeders. The 37K22 has contingency loading issues.

<table>
<tr><td>Recommended Plan</td><td>The recommended plan to address the Newport conductor limiting and voltage concerns is as follows:
Newport 203W1:
Reconductor ~160 circuit feet of 1/0 Al 3 phase overhead primary with 477 Al
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 plan to address the Kingston thermal loading and contingency concerns is as follows:
Kingston 131J12
To address the overload on 131J12, transfer load to 131J4.
Kingston 38K21
To address the contingency concern on 38K21, first the substation will need to be rebuilt due to asset condition concerns. The new substation will have 8 23 kV circuit positions. Using five (5) initially for 23 kV circuits, 38K21 from Gate 2-Kingston, 38K21 from Kingston-Hospital T2 transformer, will become radial. This will provide the operations the ability to offload the 38K21 for the N-1 38K23 OOS contingency.
The recommended plan for to relieve the load unbalance issues on the Dexter 36W42 is to transfer tap load at various locations from “A” phase to “B” phase.

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.</td></tr>
<tr><td>Alternative Plans</td><td>See area study report for alternative plans.</td></tr>
</table>

<table>
<tr><td>Long Range Plan Alignment</td><td>Newport Area Study completed December 2021</td></tr>
<tr><td>Planned Capital Spend
($000)</td><td>
<table>
<tr><th>FY 2023
(9 Months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr>
<tr><td>-</td><td>435</td><td>482</td><td>112</td><td>-</td></tr>
</table>
</td></tr>
</table>

Attachment # RR-19-15
Other Area Study Projects – System Capacity & Performance – Northwest Rhode Island

Distribution Related Project Number(s):	NWRI001 Farnum Pike 23F3 Reconductor (D-Line) NWRI002 Putnam Pike 38F3 Reconductor (D-Line) NWRI004 Smart Capacitor Installations (D-Line) NWRI005 West Greenville 45F2 Line Regulator (D-Line) NWRI006 Chopmist 34F2 Line Regulator (D-Line) NWRI007 Chopmist 34F3 Stepdown Conversion (D-Line)
Substation(s) / Feeder(s) Impacted:	Farnum Pike: 23F3 Putnam Pike: 38F2, 38F3 West Greenville: 45F2 Chopmist: 34F2, 34F3 Woonsocket: 26W1, 26W3, 26W7 Farnum: 105K1
Voltage(s):	12.47kV and 23kV
Geographic Area Served:	Burrillville, North Smithfield, Smithfield, Glocester, Scituate, Foster, a portion of Johnston
Summary of Issues:	The Farnum Pike Feeder 23F3 has approximately 0.3 miles of 1/0 ACCC section on the mainline on Route 116 that is overloaded. The Putnam Pike 38F3 has approximately 0.6 miles of 4/0 Al on the mainline on Sanderson Rd. There are several feeders with a power factor lower than 98% in need of additional reactive compensation. This includes 105K1, 26W1, 26W3, 26W7, 34F3, 38F2. The West Greenville 45F2 feeder has low voltage concerns on main line sections. The Chopmist 34F2 feeder has low voltage concerns on main line sections. The Chopmst 34F3 feeder has low voltage concerns on a single phase side tap.
Recommended Plan	The recommended plan for Farnum Pike Feeder 23F3 is to reconductor the 0.3 miles section along Route 116 with 477 Al. The recommended plan for Putnam Pike 38F3 t reconductor the 0.6 miles section from P1 to P22 on Sanderson Rd with 477 Al.

<table>
<tr><td></td><td>The recommended plan for the low power factor is to install a total of 10 smart/Advanced Capacitor banks on the following feeders:
105K1 – Install a 600 kVAR capacitor
26W1 – Install a 900 kVAR capacitor
26W3 – Install two 900 kVAR capacitors
26W7 – Install two 900 kVAR capacitors
34F3 – Install two 600 kVAR capacitors
38F2 – Install two 600kVAR capacitors
The recommended plan for the West Greenville 45F2 feeder is to install a line regulator on Hartford Pike new West Greenville Road.

The recommended plan for the Chopmist 34F2 feeder is to install a line regulator on Chopmist Hill Rd

The recommended plan for the Chompist 34F3 feeder is to remove the single phase 7.2/2.4kV Stepdown Transformer and covert the single-phase side tap to 7.2kV.</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>Northwest RI Area Study completed March 2021</td></tr>
<tr><td>Planned Capital Spend
($000)</td><td><table><tr><th>FY 2023
(9 Months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr><tr><td>1,226</td><td>707</td><td>-</td><td>-</td><td>-</td></tr></table></td></tr>
</table>

Attachment # RR-19-16
Other Area Study Projects – System Capacity & Performance - South County West

Distribution Related Project Number(s):	SCW0001 Kenyon Common Items (D-Line) SCW0002 Kenyon 68F5 Extension (D-Line) SCW0005 Langworthy Corner Feeder Ties (D-Line) SCW0007 Wood River 85T2 Line Extension (D-Line)
Substation(s) / Feeder(s) Impacted:	Kenyon: 68F1, 68F2, 68F3, 68F4, 68F5 Langworthy: 86F1 Wood River: 85T1, 85T2, 85T3
Voltage(s):	12.47kV and 34.5 kV
Geographic Area Served:	Hopkinton, Westerly, Charlestown, Richmond, Western half of South Kingstown
Summary of Issues:	Kenyon is a two transformer 115/12.47kV substation that consists of five feeders. The Kenyon Substation Feeders have a full range of issues related to voltage, power factor, and normal and contingency capacity concerns. The Kenyon 68F3, 68F4, and 68F5 feeders have poor voltage and power factor performance. The Kenyon 68F1, 68F3, and 68F3 feeders have low voltage concerns. The 68F2 out of Kenyon Substation has normal and contingency capacity concerns. A loss of the normal supply to the circuit results in a violation of our Planning Criteria, with 4.4MVA of peak unserved load and accumulating 23MWHrs by 2025. This circuit also is predicted to experience recurring violations of its Summer Normal thermal rating, up to 110% by 2025. Langworthy is a modular 34.5/12.47kV substation. A loss of the normal supply to the 86F1 circuit results in a violation of the Company's Planning Criteria, accumulating 29MWHrs by 2025. Wood River is a two transformer 115/34.5kV substation consisting of three supply lines. There are reliability concerns on the 85T1 supply line.
Recommended Plan	The recommended plan to address the voltage, power factor, and capacity concerns for all Kenyon feeder is as follows: Kenyon Smart Capacitors • Kenyon 68F3, 68F4 and 68F5, replace 3 existing, and add 4 new smart capacitor banks for voltage and power factor improvements. Kenyon Line Regulators • Kenyon 68F1, add new 167kVA regulators at Old Usquepaugh Road. • Kenyon 68F2, add new 333kVA regulators at Gravely Road.

	• Kenyon 68F3, remove existing 333kVA regulators on Old Post Road, and add new 333kVA regulators at Cross Mills Road. Extend the lightly loaded 68F5 to tie with 68F2. This new tie and additional available capacity will reduce the normal and contingency capacity concerns on the 68F2. The recommended plan for the Langworthy 86F1 contingency capacity concerns is to firm up the existing feeder ties with Westerly Substation and add one new tie point. This includes increasing the capacity on the Westerly 16F1 feeder and extending the Westerly 16F4 feeder to tie with the 86F1 feeder. The recommended plan to address the Wood River 85T1 reliability concerns is to extend the 85T2 from the vicinity of the existing Westerly Substation, approximately 20,000' to Post Road and create a new Loop Scheme with the 85T1.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	South County West Area Study completed October 2021
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
236	673	1,263	1,863	2,434

Attachment # RR-19-17

Nasonville Damage/Failure Rebuild

Distribution Related Project Number(s):	C091379
Substation(s) / Feeder(s) Impacted:	Nasonville 127, 127W40, 127W41, 127W42, 127W43
Voltage(s):	13.8kV
Geographic Area Served:	Burrillville, North Smithfield
Summary of Issues:	Nasonville 127 is a 115kV to 13.8kV substation located off Douglas Pike in Burrillville, RI. It is the only 115kV source to 9,260 Rhode Island Energy (RIE) and Pascoag Utility District (PUD) customers in the northwest most corner of RI. On the evening of August 23, 2022, during a period of unsettled weather, a fault on the W40 feeder developed causing catastrophic damage to the W40 breaker cubicle and igniting a fire which subsequently damaged the switchgear beyond reasonable repair. The fire likely caused the 115kV protection scheme to improperly operate resulting in damage to the high side air break switch. A National Grid owned mobile switchgear has been deployed to site and installed. It currently serves the 4 feeders, however there is no provision to connect the capacitor bank.
Recommended Plan	The recommended long-term solution is to replace the damaged metal clad switchgear with an open-air substation consisting of four (4) feeder breakers, one (1) capacitor bank breaker, one (1) open-air capacitor bank and associated foundations, aluminum structures, bus work and cables. RIE will be utilizing the standard Pennsylvania style substation design and the Pennsylvania standard Relay in a Box control and protection scheme. The failed (271-1) air break will be replaced with a circuit switcher under a separate Transmission funding project.
Alternative Plans	Damage Failure – No Alternative Plans available. A planning study for 2025 – 2027 calls for the station to be expanded. That project has been approved under the following funding numbers. C087770, C087752, & C087751. Together these projects add 4 feeders, 1 transformer, and 1 transmission line to the existing Nasonville 4 feeder configuration. In order for those projects to proceed the original Nasonville station needs to be rebuilt.
Long Range Plan Alignment	A planning study for 2025 – 2027 calls for the station to be expanded. That project has been approved under the following funding numbers. C087770, C087752, & C087751. Together these projects add 4 feeders, 1 transformer, and 1 transmission line to the existing Nasonville 4 feeder configuration. In

	order for those projects to proceed the original Nasonville station needs to be rebuilt. Due to supply chain constraints for the manufacturing of switchgear a decision has been made to rebuild the station using an open-air configuration built to current PA standards. This will build in the technology required to implement FLISR and other smart grid equipment on all the future Nasonville feeders, as well as allowing a substantially shorter project delivery.
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
1,092	1,637	223	-	-

Attachment # RR-19-18
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.
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.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Blackstone Valley South Area Study completed October 2021

Planned Capital Spend ($000)	**FY 2023 (9 Months)**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**
	-	173	578	1,215	1,677

Attachment # RR-19-19
Other Area Study Projects – Asset Condition – Blackstone Valley South

Distribution Related Project Number(s):	C088827 Valley and Farnum 23kV Conversion (D-Line) BSVS009 Valley #102 Sub (D-Sub) BSVS010 Valley #102 & Farnum #105 Sub (D-Line) BSVS011 Farnum #105 Sub (D-Sub)
Substation(s) / Feeder(s) Impacted:	Farnum: 105K1 Valley: 102K22 Washington: 126W40, 126W42
Voltage(s):	12.47kV and 23kV
Geographic Area Served:	Lincoln, Pawtucket
Summary of Issues:	Valley 23kV Substation is a single transformer 115/23kV substation consisting of one feeder. Farnum is single transformer 115/23kV substation consisting of one feeder. There are numerous concerns with the safety and asset conditions issues at the Farnum and Valley 23kV substations. The concerns on these 23kV substations include transformers, air breaks, regulators, VT disconnects, and lightning arrestors. Portions of these circuits in the R.O.W. are reaching their end of asset life expectancy causing increased outages and these outages are difficult for operations due to R.O.W. accessibility issues. • A recent outage on the 105K1 circuit on March 11, 2021 was caused by a crossarm asset condition in the R.O.W. When the crossarm failed, a phase came out of the insulator slowly burning the crossarm causing a fire in the brush below. • There are poles in the R.O.W. that are rotting due to exposure to weather for an extended period of time. • When outages occur in the R.O.W. it takes additional time to identify the outage due to access challenges • It is difficult to repair failures in the R.O.W due to specialized equipment needed to access the locations in the R.O.W. The age of the poles was used as a proxy for the distribution asset conditions of the feeder. On average the poles have a service life of 40 years. The table below summarizes the percent of poles on each feeder that are greater than 25 years old and greater than 40 years old.

Substation	Feeder	Total Poles	Poles > 25 Years Old	Percent > 25 Years	Poles > 40 Years Old	Percent > 40 Years
Farnum	105K1	178	139	78.1%	108	60.7%
Valley	102K22	252	204	81.0%	159	63.1%

Recommended Plan	The recommended plan is to convert the 23kV distribution feeder load to 13.8kV and transfer to surrounding 13.8kV feeders. The surrounding 13.8kV feeders are supplied by the Washington Substation. Once the transfers and conversions are complete, all the equipment at the substation will be retired and removed.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Blackstone Valley South Area Study completed October 2021
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
675	225	-	-	-

Attachment # RR-19-20
Other Area Study Projects - East Bay Substation Retirements

Distribution Related Project Number(s):	C065293 Barrington Sub Retirement (D-Sub) C065295 Kent Corners Sub Retirement (D-Sub) C065297 Waterman Ave Sub Retirement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Barrington: 4F1, 4F2 Kent Corners: 47J1, 47J2, 47J3, 47J4 Waterman Ave: 78F3, 78F4
Voltage(s):	4.16kV and 12.47kV
Geographic Area Served:	East Providence, Barrington
Summary of Issues:	Barrington is a single transformer 23/12.47kV substation that consists of two feeders. Kent Corners is a two transformer 23/4.16kV substation that consists of four feeders. Waterman Ave is a two transformer 23/12.47kV substation that consists of two feeders. There are numerous concerns with the safety and asset conditions at the Barrington, Kent Corners, and Waterman Ave Substations. The concerns on these substations include air breaks, feeder breakers, minimum clearance requirement concerns, no EMS. (See Phillipsdale Projects in the response to Recommendation 9)
Recommended Plan	The recommended plan is to build two new 115/12.47kV substations (Phillipsdale, First St) and reduce the loading and dependence on the 23kV sub transmission system. The installation of these two new substations will allow for the retirement of the Barrington, Kent Corners, and Waterman Ave Substations. The distribution feeders supplied by these substations will be transferred to First St, Wampanoag, Phillipsdale, and Warren feeders and the equipment at the substation will be retired and removed. This approach eliminates the 4kV pocket at Kent Corners and eliminates a major investment on the 23kV stations to address the asset condition concerns. (See Phillipsdale Projects in the response to Recommendation 9)
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 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
-	-	19	6	-

Attachment # RR-19-21
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) NWPT004 Kingston #131 Equipment Replacement (D-Sub) NWPT005 Eldred 45J3 Reconfiguration (D-Line) NWPT006 Dexter 36W44 Asset Replacement (D-Line) NWPT008 CLX Cable Replacement (D-Line) NWPT014 Merton #51 Equipment Replacement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Dexter: 36W41, 36W42, 36W43, 36W44 Gate II: 38J2, 38J4 Hospital: 146J2, 14J4, 146J12, 146J14 Kingston: 131J2, 131J4, 131J6, 131J12, 131J14 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, Hospital #146, Kingston #131, and Merton #51. 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. The CLX Cable has operational issues that include deterioration, low ampacity, and lack of expertise in splicing and repairing.
Recommended Plan	The recommended plan is to address the asset conditions at Dexter #36, Gate 2 #38, Hospital #146, Kingston #131, and Merton #51. 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 LTC transformers. The existing 461 transformer will be rebuilt and refurbished and stored as a spare. • Replace all the existing AMCBs, 146J2, 146J12, 146J4, 146J14, and 4600, with VCBs. 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, VCB 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) Merton #51: • Replace the two (2) existing 23/4.16 kV supply transformer and AMCB switchgear with two (2) new 23/4.16 kV transformers and 4.16 kV, VCB, 4 feeder and two (2) future capacitor banks, breaker and a half scheme switchgear lineup. The recommended plan is to address the distribution line asset conditions concerns at Eldred 45J3, Dexter 36W44, and CLX. The required replacement work is shown below. Eldred 45J3: • 2,700 Circuit feet of single phase overhead primary to be upgraded to 3 phase on Beach Ave • 550 circuit feet of UG 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 CLX Cable replacement: • Replace 11,500 circuit feet of single phase and 22,300 circuit feet of 3 phase, vintage 1960's, 5 kV, rubber armored direct buried cable.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Newport Area Study completed December 2021
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
-	4,273	7,424	9,104	8,847

Attachment # RR-19-22
Other Area Study Projects – Asset Condition - Northwest Rhode Island

Distribution Related Project Number(s):	NWRI003 West Greenville Air Break Replacement (D-Sub)
Substation(s) / Feeder(s) Impacted:	West Greenville: 45F2
Voltage(s):	12.47kV
Geographic Area Served:	Smithfield, Glocester, Scituate
Summary of Issues:	West Greenville is a modular 23/12.47kV substation. There are asset concerns on the 451 and 452 Motor Operating Air Breaks at the West Greenville Substation. The control cabinet for the transfer scheme is in poor condition. There is no guarantee the scheme would work as designed due to the visual condition of the equipment.
Recommended Plan	The recommended plan is to address the asset concerns at the West Greenville Substation. That includes the following: • Install new swing panel for controls for the new 451 and 452 switches. • Replace the existing DC panel. • Install new conduits from the 451 and 452 MOD controls to control enclosure. • Replace Two (2) 23kV motor operated air break switches. • Replace One (1) 250VDC panel inside control enclosure.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Northwest RI Area Study completed March 2021
Planned Capital Spend ($000)	see table below

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
270	131	-	-	-

Attachment # RR-19-23
Other Area Study Projects – Asset Condition Providence

Distribution Related Project Number(s):	PROV001 Auburn Substation 4kV conversions common (D-Line) PROV002 Auburn Substation 4kV conversions (115kV option) (D-Line) PROV003 Elmwood 7F4 Rebuild Common (D-Line) PROV004 Pontiac 27F2 Rebuild Common (D-Line) PROV005 Lincoln Ave 72F6 Load Break (D-Line) PROV006 23 kV conversions 2213 & 2235 (D-Line) PROV007 Lakewood, Sockanosset 23 kV & Lincoln Ave (D-Line) PROV008 Huntington Park 4 kV Convert (D-Line) PROV009 Sprague St 4 kV Convert (D-Line) PROV010 Point St and Dyer St associated with Sprague (D-Line) PROV011 Auburn 115/12.47kV (D-Line) PROV012 Auburn 115/12.4kV Substation (D-Sub) PROV013 2235 Removals (D-Line) PROV014 Huntington Park Sub Removal (D-Sub) PROV015 Sprague St Sub Removal (D-Sub) PROV016 Remove Supply Cables to Sprague St (D-Line) PROV017 Lakewood Sub Removal (D-Sub) PROV018 Sockanosset Removal (D-Sub) PROV019 Getaways (Geneva, Knightsville, & Lippitt Hill) (D-Line) PROV020 East George 77J2 Conversion (D-Line) PROV021 Geneva – Modular (D-Sub) PROV022 Knightsville – Modular (D-Sub) PROV023 Lippitt Hill 3rd Feeder (D-Sub)
Substation(s) / Feeder(s) Impacted:	Auburn: 73J1, 73J2, 73J3, 73J4, 73J5, 73J6 Elmwood: 7F4, 2213 Pontiac 27F2 Lincoln Ave: 72F6 Sockanosset: 2233, 2235 Huntington Park: 67J1 Sprague St: 36J1, 36J2, 36J4, 36J5 Lakewood: 57J1, 57J2, 57J3, 57J5 East George: 77J2
Voltage(s):	4.16kV, 13.8kV, and 23kV
Geographic Area Served:	Providence, Cranston, Johnston, North Providence

Summary of Issues:	Providence is an urban area with a relatively concentrated load. The electrical distribution facilities consist of a mix of older 11 kV and 4.16 kV distribution systems and a newer 12.47 kV distribution system. The distribution circuits are primarily underground in the downtown business district whereas they are overhead in the surrounding residential areas. Much of the underground infrastructure dates back to the period when the system was originally installed in the 1920's. The study identified the main issue to be asset condition. Six of the older stations supplying the area are indoor stations installed between 1924 and 1939 and have a number of asset related concerns. The health and condition of all indoor stations were assessed, and each station assigned a priority score. In addition to the station issues, over 25 miles of underground supply and distribution circuits were identified in the Company's cable replacement program.
Recommended Plan	The Providence Study assessed various options to resolve issues identified within the study area and compared the economics of several supply and distribution alternatives. The preferred option recommended the expansion of the 12.47 kV distribution system, conversion of the majority of 11.5 kV and 4.16 kV load to 12.47 kV and elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations. The majority of the new 12.47 kV capacity in the recommended plan would be provided by new 115/12.47 kV stations at Admiral Street, Auburn and South Street. The first phase of the Providence Long Term Study is in progress. The second phase of the Providence Long Term Study includes the following work: • Build a new 115/12.47 kV substation, open air low profile with a breaker and one half design, at the existing Auburn substation site with two 115/12.47 kV 33/44/55 MVA transformers, eight feeder positions, and two 7.2 MVAr station capacitor banks. • Extend two 115 kV transmission lines, I-187 and J-188, from Sockanosset substation approximately 1.10 miles north to the proposed Auburn substation. This proposed transmission line extension will be located within the existing 23 kV sub-transmission right-of-way and no new rights are anticipated to be required. • Modify the area distribution due to the eight new feeders from Auburn substation. Retire the Auburn 23/4.16 kV station, the Lakewood 23/4.16 kV station, and the Sockanosset 115/23 kV station. The 12.47 kV capacity at Auburn will also be used to convert the 4.16 kV load at Huntington Park and Sprague Street substations and allow for their retirement.

	• New 12.47 kV feeders are proposed at Geneva, Knightsville and Lippitt Hill substations in 2030 to resolve these MWh violations. A review of feeder loads and non-wires alternatives should be re-evaluated prior to the construction of new 12.47 kV feeders.
Alternative Plans	See area study report for alternative plans.
Long Range Plan Alignment	Providence Area Study completed May 2017
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
-	1,522	3,552	6,420	6,522

Attachment # RR-19-24
Other Area Study Projects – Asset Condition – South County West

<table>
<tr><td>Distribution Related Project Number(s):</td><td>SCW0006 Wood River Substation (D-Sub)
SCW0008 Westerly Asset Condition (D-Sub)</td></tr>
<tr><td>Substation(s) / Feeder(s) Impacted:</td><td>Wood River: 85T1, 85T2, 85T3
Westerly: 16F1, 16F2, 16F3, 16F4</td></tr>
<tr><td>Voltage(s):</td><td>12.47kV and 34.5 kV</td></tr>
<tr><td>Geographic Area Served:</td><td>Hopkinton, Westerly, Charlestown</td></tr>
<tr><td>Summary of Issues:</td><td>Wood River is a two transformer 115/34.5kV substation consisting of three feeders. There are numerous asset conditions concerns at the substation. These concerns include the out of service capacitor bank, the station service, the 115kV tie breaker, and the 115kV CCVTs.

The Westerly Substation is a two transformer 34.5/12.47kV substation with four feeders. There numerous asset condition concerns at the substation. These concerns include the 16F4 feeder regulator, the capacitor banks, and the lightning arrestors.</td></tr>
<tr><td>Recommended Plan</td><td>The recommended plan for the Wood River Substation is to address the asset concerns at the substation. This includes the following upgrades:
Replace LTC controls for both transformers to allow for full SCADA control
Replace both station service transformers
Replace single stage out of service capacitor bank with larger, two stage configuration
Replace 115kV CCVTs and tie breaker and associated protective relays
The recommended plan for the Westerly Substation is to address the asset concerns at the substation. This includes replacing the 16F4 feeders regulator, replace the non-operational capacitor banks, and replace the outdated lightning arrestors.</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>South County West Area Study completed October 2021</td></tr>
<tr><td>Planned Capital Spend
($000)</td><td><table><tr><th>FY 2023
(9 Months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr><tr><td>-</td><td>-</td><td>-</td><td>-</td><td>772</td></tr></table></td></tr>
</table>

Attachment # RR-19-25
Grid Modernization Plan – Advanced Distribution Monitoring System (ADMS)

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, operators rely on static system models and the distribution status information in SCADA (where available) to make operations decisions. For planned and emergency feeder reconfigurations, the operators utilize historic peak loading and nameplate data, to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER, EV charging, and gas to electric heating conversion where daily, seasonal and locational variability is increasing. In addition, any advanced automation schemes (e.g., VVO/CVR) have been difficult to develop and are currently built as stand-alone functions to the extent the capability is available. The operators can monitor the actions of the programs via the SCADA system, but they run independently based on "as-designed" feeder configurations rather than adapting to the real-time "as-switched" feeder configuration meaning, automation schemes may be disabled if the distribution grid is out of its normal state. Finally, the Company aspires to expand the number of field devices that will be integrated with the existing SCADA system which will significantly increase the amount of data brought back from distributed devices. As a result, existing capacity will be strained and capabilities will be needed that exceed existing applications. The distribution system will no longer be able to be operated in a safe and reliable manner without a robust ADMS/SCADA system capable of facilitating the following primary functionalities; OMS, FLISR, VVO, DER Monitor/Manage/Control/Power Flow, Auto-reconfiguration, etc.
Recommended Plan	A condition that accompanied the PPL acquisition of Narragansett was to provide the ADMS Basic as a condition of the sale where deployment was named on the Transition Service Agreement (TSA). The strategy is to align RIE ADMS systems to mirror the current ADMS architecture and functions that PPL has used as close as possible. The scope of this investment includes incremental ADMS functionality being developed beyond ADMS Basic to satisfy RIE requirements. Various ADMS functionalities have been defined to be released over the five-year period.

	The proposed ADMS investment is an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. The Company believes ADMS is a critical platform for the integration and operational management of DERs as their impact on grid performance grows, and ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices, DERs, and AMF data as it becomes available. For example, when planning to reconfigure the grid, ADMS will allow the operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach and ensure the most efficient switching that yields optimal power quality. DERs will be operationally integrated into the ADMS network model to allow operators to assess their effect on the grid, as well as leverage them for support where possible. The project will be implemented utilizing a phased approach putting different modules and functionality into service over the next five years. This will maximize value add and benefits realization as early as possible as well as help to align ADMS with critical system interfaces and dependencies such as GIS, data model expansion, and RTU separation. To date, the Company has completed an analysis and scoping effort for the development of the RIE ADMS expansion, ADMS-based application solutions include - Protection and Arc Flash App, VVO/CVR App, FLISR App, DERMS. ADMS basic is included in the Transition Service Agreement (TSA) with PPL. This project will apply only to ADMS advanced applications. ADMS based Arc & Flash Protection - Software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid. VVO/CVR Platform - Accelerated deployment of software with control schemes to coordinate multiple voltage regulating devices (i.e., Advanced Capacitors & Regulators) on a feeder to achieve optimal CVR performance and reduce customer demand and energy use.

	ADMS based FLISR application - Software with overlaying control scheme to coordinate multiple load management devices (i.e., Advanced Reclosers & Breakers) on a feeder to achieve fast, reliable, and safe FLISR, which can reduce customer outage restoration time. DERMS - Suite of software tools to integrate customer controlled DER resources with grid operations, including dispatching DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution.
Current Status and Expected In-Service Date	This program is included in the FY23 ISR and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced “smart” technologies that can actively manage energy use in customers’ homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have no visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. ADMS coupled with other GMP investments will provide the situational awareness that is necessary to protect safety and reliability, enable the efficient achievement of the state’s clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear.

<table>
<tr><td></td><td>Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs.

The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan.

In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system more expensive for customers in the long run and less able to generate desired benefits, and will create systemic strain on the electric distribution system. On the other hand, grid modernization based on a well-coordinated and integrated GMP will help maximize operational, customer, and clean energy benefits for all customers.</td></tr>
<tr><td>Long Range Plan Alignment</td><td>The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed.

Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.</td></tr>
<tr><td>Planned Capital Spend
($,000)</td><td><table><tr><th>FY 2023
(9 Months)</th><th>FY 2024</th><th>FY 2025</th><th>FY 2026</th><th>FY 2027</th></tr><tr><td>107</td><td>143</td><td>3,230</td><td>1,600</td><td>4,480</td></tr></table></td></tr>
</table>

Attachment # RR-19-26
Advanced Reclosers

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 distribution system has traditionally been built to ensure adequate available capacity at all times by building the necessary distribution system capacity to accommodate forecasted peak loading on extreme weather days in accordance with the Company's planning criteria. Designing the system to meet these worst-case scenarios assuming one-way power flow eliminated or lessened the need for day-to-day load management for distribution grid management. In addition, when a fault does occur on the system, restoration has been made possible by manually switching to isolate the fault and serving with power from alternative sources where possible. As DER penetration increases and is located anywhere on the distribution system it will result in possible two-way power flow, overloads in the reverse direction under light load conditions, and desensitization of protection systems during fault conditions. Similar to voltage management, the increasing complexity of the grid will require a transition away from simple autonomous controls to control schemes that are integrated across an entire feeder. The load control and near real-time power measurements provided by Advanced Reclosers when used in combination with ADMS enable engineering and operations personnel to automatically isolate faults and restore service (FLISR) and better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all RIE customers through optimization. An accelerated deployment of Advanced Reclosers is being proposed to ensure distribution equipment is operated within its rated capacity and that faults on the system are cleared efficiently. Those areas and feeders with existing DER penetration and the greatest overload and/or protection coordination risk will be prioritized. The targeted deployment of Advanced Reclosers is part of the Company's GMP is forecasted to reduce both the duration and frequency of outages.

Recommended Plan	The GMP proposes investment in Advanced Reclosers on the Distribution class systems, taking into consideration Area Study solutions which may call for the reconfiguration and or conversion of certain circuits. The proposal calls for the installation of both main line and tie point reclosers.
Current Status and Expected In-Service Date	This program is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as reclosers are installed. The funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters and be empowered with real-time control to maintain reliability as the system becomes increasingly complex and dynamic. Advanced Reclosers when coupled with ADMS will provide the situational awareness and real-time control that is necessary to protect safety and reliability, enable the efficient achievement of the state's clean energy goals, improve operational efficiency of the distribution system, and reduce O&M cost. This investment will avoid outages, reduce the impact of them and obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear to continue to enjoy a reliable electric system as increased DER penetration manifests and heating and transportation electrifies. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to

	be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan. In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system already underway more expensive for customers in the long run and less able to generate desired benefits, and will create systemic strain on the electric distribution system. On the other hand, grid modernization based on a well-coordinated and integrated GMP will help maximize operational, customer, and clean energy benefits for all customers.
Long Range Plan Alignment	The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed. Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.
Planned Capital Spend ($000)	see table below

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
15,681	20,908	26,172	26,696	27,230

Attachment # RR-19-27
Grid Modernization Plan – DER Monitor Managed

Distribution Related Project Number(s):	TBD
Substation(s) / Feeder(s) Impacted:	All
Voltage(s):	Distribution and Point-of-Interconnect voltage
Geographic Area Served:	System Wide
Summary of Issues:	The electric transmission and distribution systems in Rhode Island are currently undergoing significant changes due to the increasing deployment and use of DERs, upending the traditional electric grid architecture that has been supplied with centralized, large scale generation located at significant distances from customers. By allowing customers to both consume and produce electricity at what were traditionally points of delivery, DERs force the electric distribution system to perform in a way for which it was not originally designed and, as a result, places an increasing stress on the grid. As DERs in Rhode Island continue to increase, the Company still must provide reasonable, safe, reliable, and affordable electric service to all of its customers, including those who have not installed DERs. This can be particularly difficult because electricity cannot be readily stored and generation and load must be balanced at all times. Today, transmission operators, such as ISO-NE, manage the transmission grid by maintaining a balance between demand and generation through monitoring and controlling generation assets instantaneously. Traditionally, distribution operators did not have to worry about balancing demand and generation because the distribution grid had very little generation connected to it. However, as the penetration level of DER increases, the classical model of distribution systems is not well-equipped to handle the simultaneous balancing of demand and generation. Therefore, as distribution systems become increasingly similar to transmission, i.e., a mix of demand and generation, the need to balance generation and demand becomes critically important. Such balancing cannot be accomplished without the ability to monitor and manage generation assets on the grid. As more DERs are interconnected with the Company's distribution system, RIE will have to balance demand and generation simultaneously and will increasingly experience issues on its distribution without any way to monitor and manage those resources. Solar and other intermittent resources can negatively affect the voltage on the electric distribution system, resulting in delayed interconnection or distribution system reinforcements before additional DERs can be installed. Given RIE's current inability to directly communicate with and manage DERs to mitigate resulting power quality issues and to leverage grid support

	functionality, the amount of intermittent generation that can be interconnected must be limited to maintain system stability and reliability. Moreover, in the absence of such ability, the reliability, safety, and efficiency of RIE's service will be placed at increased risk with each new DER that is interconnected with the distribution system. The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that enables more DERs to connect, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. As more DERs connect to the system, the devices need to be integrated with utility operations at all levels for management and monitoring purposes. By way of background, many utilities have experienced operations and planning challenges as DER penetration becomes increasingly significant. These challenges include, but are not limited to, voltage swings, masked or hidden load, limited hosting capacity, planning uncertainties, and protection/operational challenges with two-way power flow. In response to these challenges, the Institute of Electrical and Electronics Engineers ("IEEE") revised Standard 1547 in 2018 ("IEEE 1547-2018"), which set forth requirements for smart inverters that can help support the distribution system. When these smart inverters are coupled with DER management devices, electric utilities can monitor and manage DERs interconnected with their distribution systems.
Recommended Plan	Plan developed based on the projected DER connections by year and the cost per connection. There are 2 connection options: 1. Current Solution (price range \$555 - \$929 depending on addition of electrical collar) 2. Solution supporting 2030.5 (projected price range \$1500 - \$1555 depending on addition of electrical collar) Assumptions were made based on 60% split to current solution and 40% split to 2030.5 solution and PPL's experience with percentage of customers that purchase the electrical collar.
Current Status and Expected In-Service Date	This program is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the

	energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have no visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs – driven by commercial and roof top solar PV – reliability of the network and safety for both utility crews and the general public can no longer be maintained. With this unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. GMP will provide the situational awareness that is necessary to protect safety and reliability, enable the efficient achievement of the state's clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan. In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system already underway more expensive for customers in the long run and less able

<table>
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<tr><td>Long Range Plan Alignment</td><td>The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed.

Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.</td></tr>
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<table>
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Attachment # RR-19-28
Grid Modernization Plan – 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, distribution, and their regulation continuously evolve. The equipment monitoring and protecting the power system needs to be flexible to meet these changes. Rhode Island's 2021 Act on Climate set enforceable, statewide, economywide greenhouse gas emissions mandates to achieve net-zero emissions by 2050 and the 2022 amendments to the Renewable Energy Standard further specify a schedule of electricity to be generated by 100% renewable energy resources by 2033. This transition will remove the inertia-based generation that has long stabilized system frequencies, and replace it with variable sources that require more intelligent monitoring devices. Intelligent and automated decision-making is becoming more important than ever for RIE to maintain operating costs, safety, and provide electric service reliability. Electromechanical Relays, which are predominate in substations are dated and provide little data or flexibility that will be needed to manage and operate in the future. Digital relays, adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups. Additionally, the fault location information provided by digital relays minimizes outages and reduces the time field technicians spend searching for issues. Improving how the power system is monitored and controlled can provide operations and maintenance benefits that exceed the initial capital investment. There are many advantages to upgrading old electromechanical, solid-state, and first-generation electromechanical relays; for example reliability increases because there is less direct wiring and interconnection wiring. Reliability and security of multifunction logic and settings are improved with next-generation user interface software. Remote input/output modules, remote analog/digital inputs, and thermal measurement capabilities have expanded the protection, control, and monitoring. New protection and monitoring features improve power system equipment life and increase personnel safety. Maintenance costs are reduced, while internal watchdogs alert the user if the relay has a problem. Settings groups can be changed instantaneously to adapt to varying power system requirements. Digital relays offer a variety of secure

	communications capabilities for interfacing with Smart Grid controls, SCADA systems, and business networks. Event memory is larger for more on-board, standardized oscillographs and event reporting. Data from the upgraded relays is used in conjunction with software to predict failures before they occur, respond faster to incidents and integrate data with business processes to make the Company more efficient and reliable which will result in customer savings, improved services and increased customer satisfaction.
Recommended Plan	The GMP proposes 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 is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28

Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have limited visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs – driven by commercial and roof top solar PV – reliability of the network and safety for both utility crews and the general public can no longer be maintained. With this unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, reverse power flow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. GMP will provide the situational awareness that is necessary to protect safety and reliability, enable the efficient achievement of the state's clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan.

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<tr><td>Long Range Plan Alignment</td><td>The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed.

Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.</td></tr>
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</table>

Attachment # RR-19-29
Grid Modernization Plan – Fiber

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. With the proliferation of GMP and AMF automated devices, there is a significant need to send data to /from them to software systems and customer portals quickly to visualize, monitor, and manage the distribution system and interact with customers in near-real time. Cellular limitations do not offer adequate functionality and add reliability and resiliency system risk. The GMP is proposing for RIE to own, operate and maintain a private fiber network in Rhode Island to support communications to substation relays and to back-haul AMF data. This investment will replace leased cellular services that currently provide communications for substations.
Recommended Plan	Replace cellular services connecting substations with fiber optic cabling to improve data flow and reliability of communications.
Current Status and Expected In-Service Date	This program is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including

	increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have no visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs – driven by commercial and roof top solar PV – reliability of the network and safety for both utility crews and the general public can no longer be maintained. With this unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. GMP will provide the situational awareness that is necessary to protect safety and reliability, enable the efficient achievement of the state's clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan. In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system already underway more expensive for customers in the long run and less able to generate desired benefits, and will create systemic strain on the electric

	distribution system. On the other hand, grid modernization based on a well-coordinated and integrated GMP will help maximize operational, customer, and clean energy benefits for all customers.
Long Range Plan Alignment	The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed. Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.
Planned Capital Spend ($000)	

FY 2023 (9 Months)	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**
8,571	11,428	18,000	16,000	8,000

Attachment # RR-19-30
Grid Modernization Plan – 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:	Managing the distribution system more granularly in order to safely, reliably, and cost effectively meet customer's evolving expectations will depend on the Company's ability to manage, analyze, and share underlying information or data. Managing high levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices, AMF, and other technologies, there will be an enormous growth of incoming data. The proposed underlying IT infrastructure investments in data management, enterprise integration platform, and corporate PI historian are necessary to enable grid modernization functionalities and realize its full benefits. 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 GMP 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 is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service:

	• The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced “smart” technologies that can actively manage energy use in customers’ homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have no visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs – driven by commercial and roof top solar PV – reliability of the network and safety for both utility crews and the general public can no longer be maintained. With this unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. GMP will provide the situational awareness that is necessary to protect safety and reliability, enable the efficient achievement of the state’s clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing 11 area studies to review the impact of a well-coordinated GMP vs. using the historical methods for selecting projects/programs for inclusion in the ISR.

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Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.</td></tr>
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Attachment # RR-19-31
Grid Modernization Plan – 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	The GMP proposes investment in mobile dispatch system and devices.
Current Status and Expected In-Service Date	This program is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Keep current practices in place and miss the opportunity to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.
Long Range Plan Alignment	The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible

	and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed. Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.
Planned Capital Spend ($000)	

FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027
75	100	175	200	200

Attachment # RR-19-32
Grid Modernization Plan – Smart Capacitors & Regulators

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:	For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range. The Company is obligated to follow ANSI1 voltage standards for maintaining acceptable levels of voltages where the customer is interconnected to the distribution system. The service voltages should be within ±5% of the nominal voltage. Currently, the Company relies primarily on traditional voltage regulation equipment such as load tap changer (LTC), mid-line voltage regulators, and capacitors for voltage regulation installed on the primary side of the distribution circuit. In the past, voltage regulation was relatively predictable. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. These simple autonomous settings, however, will be insufficient to maintain compliance with voltage standards for feeders with a high level of intermittent renewable generation and two-way power flows. The shortcomings of traditional voltage regulation equipment is limited number of operations per day, lack of fine control on voltages, and their indirect control over secondary voltages became evident with the higher penetration levels of distributed generation and electric vehicle charging loads. Specifically, load-based DERs, such as EVs, are forecasted to create under-voltage issues during peak load periods, and generation-based DERs, such as solar and wind DG, are forecasted to create overvoltage during light load periods. The proposed Advanced Capacitors & Regulators would adjust system voltages up or down in a dynamic manner to accommodate the variable output of these DER technologies. In addition, the voltage control and near real-time power measurements provided by these devices enable engineering and operations personnel to better manage capacity and voltage along individual feeders,

[1] American National Standard for Electric Power Systems and EquipmentVoltage Ratings (60 Hertz). Nat. Electr. Manuf. Assoc., Washington, DC, USA

	ultimately resulting in lower costs to all RIE customers through optimization (e.g., VVO/CVR).
Recommended Plan	The GMP proposes investment in advanced capacitor and regulators. Approximately 10% of the existing capacitor population includes advanced controls. This plan will upgrade the remaining capacitor population. Similarly, less than 5% of the existing line regulator population includes advanced controls. This plan will upgrade the remaining population. For optimization in certain areas of the state, additional capacitor and regulators will be installed.
Current Status and Expected In-Service Date	This program is included in the 2024 ISR Proposal and will also be included in the GMP BCA filing in December 2022. Expected In-Service: • The program will be placed in service incrementally as components are completed, the funding requested includes 4/1/23 – 12/31/28
Alternatives:	Alternative: Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs. Today the distribution system operators have no visibility or real-time situational awareness of the RI electric distribution system. With the growing number of DERs – driven by commercial and roof top solar PV – reliability of the network and safety for both utility crews and the general public can no longer be maintained. With this unprecedented growth in DERs coupled with much higher peak demand and energy growth caused by additional electric vehicle charging and gas to electric home heating conversion, the operators must be able to observe in real-time sudden changes in voltage, backflow on distribution lines, and other key operating parameters. In other words, the operators can no longer only observe what is happening at the major substations but must monitor and operate each distribution feeder based on real-time conditions. GMP will provide the situational awareness that is

	necessary to protect safety and reliability, enable the efficient achievement of the state's clean energy goals, improve operational efficiency of the distribution system, reduce O&M cost, and will obviate millions of dollars in infrastructure that RI consumers would otherwise have to bear. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in a way that benefits all customers and meets the identified needs. The company is performing a state-wide review to analyze forecasted system impacts of load and generation with and with-out grid modernization. This provides a comprehensive alternative analysis evaluating the additional infrastructure costs that would be needed if the grid modernization investments were not pursued. While the study is still being conducted, preliminary results show that a no grid modernization plan would be uneconomic as compared to a grid modernization plan. In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system already underway more expensive for customers in the long run and less able to generate desired benefits, and will create systemic strain on the electric distribution system. On the other hand, grid modernization based on a well-coordinated and integrated GMP will help maximize operational, customer, and clean energy benefits for all customers.
Long Range Plan Alignment	The pending Grid Modernization Roadmap will present a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. The Grid Modernization Roadmap is informed by the Area Study solutions, which were all complete in December of 2021. In certain scenarios Grid Modernization analysis revises preferred solutions so that the most optimal plan will be executed. Grid Modernization Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), Communication Technology, and DERMS.
Planned Capital Spend ($000)	

	FY 2023 (9 Months)	FY 2024	FY 2025	FY 2026	FY 2027	
	5,143	6,857	6,900	7,000	7,000	

Record Request No. 20

Request:

How many crews will be available each day to install the reclosers?

Response:

The Company is resourcing the effort to install both the Mainline and Grid Mod reclosers as a single construction effort. Crew sizes vary between internal crews and contractors, so the only way to answer the question is to provide the average number of construction workers that will be assigned to install reclosers.

The Company reviewed the work plan and determined that our internal resources, with all their other work, should be able to install 75 reclosers over the course of the year and the balance, 325, will be installed by a dedicated contractor team. Based on the review, the Company anticipates, on an average day, 7.5 construction workers will be dedicated to installing reclosers.

Redacted

Record Request No. 21

Request:

With respect to the recloser programs, please provide a comparative cost of using RI Energy crews versus outside contractors.

Response:

To ensure an apples-to-apples installation cost comparison, the Company focused on work orders that were solely designed for recloser installations during a similar time of year for both an internal crew and contractor crew. When internal crews and contractors install reclosers as part of larger projects, it is difficult to isolate those specific costs from the other construction activities. The time of year restriction ensured we are not looking at productivity changes due to either summer or winter construction. The data set that met these requirements included reclosers installed in December 2022. The size of the sample is twelve; nine being installed by internal crews and three by contractors.

The costs shown in the table below include internal labor and benefits, contractor invoices, and construction equipment actuals for all the work orders. The average cost for the internally installed reclosers was [redacted] and for contractor installations the average cost was [redacted]. Considering the small sample size, traffic control/site condition differences, and variations in the actual scope, these costs are essentially identical.

Recloser Labor/Contractor Cost Summary - (Construction Complete Reclosers Installed in December 2022)			
Installation Resources	**Number of PTRs**	**Total Labor Installation Costs* for all PTRs**	**Average Labor Installation Cost per PTR**
Contractors	3	[redacted]	[redacted]
Internal Crews	9	[redacted]	[redacted]
Combined	12	[redacted]	[redacted]

* Cost data as of March 10, 2023 includes labor, benefits, construction vehicles, and contractor costs

Prepared by or under the supervision of: Daniel Glenning

Certificate of Service

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.

___________________________________ March 17, 2023
Joanne M. Scanlon Date

Docket No. 22-53-EL – RI Energy's Electric ISR Plan FY 2024
Service List as of 2/8/2023

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