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

Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan

Responses to Division Data Requests Sets 2 through 6

Book 3 of 3

December 21, 2023

Docket No. 23-48-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
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Rhode Island Energy™
a PPL company

December 21, 2023

VIA ELECTRONIC MAIL AND HAND DELIVERY

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

RE: Docket No. 23-48-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year ("FY") 2025 for review and approval by the Public Utilities Commission ("PUC" or "Commission"). This Electric ISR Plan is being filed in accordance with R.I. Gen. Laws § 39-1-27.7.1(d).[1] The Company respectfully requests that the PUC approve the enclosed Electric ISR Plan as filed.

On October 13, 2023, the Company submitted an earlier version of the enclosed Electric ISR Plan to the Division of Public Utilities and Carriers ("Division"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the Division worked in cooperation with the Company to reach an agreement on a proposed plan to be filed with the Commission. Specifically, the Company consulted with the Division's representatives and received and responded to discovery requests from the Division. As a result of this process, the earlier version of the Plan was refined resulting in the enclosed Electric ISR Plan. The Division has indicated general concurrence with the enclosed Electric ISR Plan.

In support of the Electric ISR Plan, the Company has included joint pre-filed direct testimony of Witnesses Nicole Gooding, Christpher Rooney, Kathy Castro, Ryan Constable, Eric Wiesner, and Daniel Glenning ("Joint Testimony"). As explained in their joint testimony, the Company is proposing spending of $140.9 million for capital investment (approved FY 2024 was $112.3 million); $13.1 million of vegetation management O&M spending (approved FY 2024 was $13.95 million); and $1.1 million of Other O&M spending (approved FY 2024 was $1.16 million).

[1] In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the enclosed Plan addresses (i) capital spending on electric infrastructure; (ii) operation and maintenance ("O&M") expenses on vegetation management; (iii) O&M expenses on system inspection; and (iv) other costs related to maintaining the safety and reliability of the electric distribution system ("Other O&M"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses revenue requirement, rate design, and bill impacts.

In addition, the Plan includes a line item for Advanced Metering Functionality ("AMF") capital spending of $51.7 million which, when added to the $140.9 million of capital investment, results in total capital spending contained within the FY 2025 Electric ISR Plan of $192.6 million.[2]

The Company's FY 2025 Electric ISR Plan total net capital investment component of the revenue requirement is $54.2 million (approved FY 2024 was $55.4 million). Separately, the total net capital investment component of the AMF revenue requirement for FY 2025 is $4.7 million; however, that amount is fully offset by deferral balances, and does not have an impact on rates in FY 2025. Please note that, in this case, the revenue requirement calculation also includes an adjustment for the tax hold harmless impact on ISR rate base. The Company has included joint pre-filed direct testimony of Witnesses Stephanie A. Briggs, Jeffrey D. Oliveira, and Natalie Hawk that describes the calculation of the Company's revenue requirement and tax hold harmless impact.

For a residential customer receiving Last Resort Service ("LRS"), and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill decrease of $0.16, or -0.1%. As mentioned above, the inclusion of AMF capital spending in the Plan does not have an impact on the rates this fiscal year. The Company has included pre-filed direct testimony of Witness Tyler Shields to describe the customer bill impacts of the proposed rate changes.

The Company is also enclosing copies of the Company's responses to six sets of discovery issued by the Division pertaining to the Plan. Please be advised that Attachments DIV 1-23; DIV 1-24-2 through DIV 1-24-16; DIV 2-5-4 through DIV 2-5-6; DIV 2-14-1 through DIV 2-14-6; DIV 2-27-3; DIV 2-30-1; and DIV 2-31-1 through DIV 2-31-3 contain confidential and privileged information. For DIV 1-24-2 through DIV 1-24-16, the Company is reviewing the attachments for Critical Energy Infrastructure Information ("CEII"). Following completion of its review, which is anticipated to be by January 31, 2024, the Company will amend the pertinent Motion and provide updated public versions of the attachments.

Pursuant to 810-RICR-00-00-1.3(H)(3), R.I. Gen. Laws § 38-2-2(4)(A)(I)(b), and R.I. Gen. Laws § 38-2-2(4)(B), the Company respectfully requests that the Commission treat the information redacted in the public version as confidential.

In support of this request, the Company has enclosed four (4) Motions for Protective Treatment of Confidential Information. 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").

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[2] The proposed ISR Plan capital investments, and the forecasts of future years' capital investments contained within the ISR Plan, do not represent the total amount of capital investment anticipated by the Company in this year and future years. In this ISR Plan, the proposed capital investments and forecasts of future capital investments only include those amounts that the Company has proposed, or, with respect to future years, plans to propose, to recover through the ISR mechanism.

Also included in this filing, attached as an exhibit to the Joint Testimony, is the Company's Second Proposed Electric ISR Plan Budgetary and Reconciliation Framework for review by the Commission. This filing stems from Docket No. 23-34-EL. The Company respectfully requests that the Commission approve the proposed framework.

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. 23-48-EL Service List
John Bell, Division (w/confidential information)
Greg Booth, Division (w/confidential information)
Christy Hetherington, Esq.
Al Contente, Division

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN	)	DOCKET NO. 23-48-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 (the "Company") hereby respectfully 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 Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachments DIV 2-5-4 through 2-5-6; 2-14-1 through 2-14-6; and 2-31-1 through 2-31-3 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the Second Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachments in accordance with 810-RICR-00-00-1.3(H) and 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

The Confidential Attachments, which are the subject of this Motion, are 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.

The Confidential Attachments consist of financial and commercial information. The Company would customarily not release this information to the public. The Company's submission of the Confidential Attachments stem from data requests issued by the Division in the above-referenced docket. Accordingly, the Company is providing the Confidential Attachments to fulfil its regulatory responsibilities.

In addition, the release of the Confidential Attachments is likely to cause substantial harm to the competitive position of the Company. The Attachments contain commercially sensitive market information, the disclosure of which could affect the Company's ability to negotiate competitive terms with its contractors. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

III. CONCLUSION

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

Respectfully submitted,

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

By its attorney,

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

Dated: December 21, 2023

CERTIFICATE OF SERVICE

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.

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Joanne M. Scanlon

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY'S FY 2025 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN	)	DOCKET NO. 23-48-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 (the "Company") hereby respectfully 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 Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachments DIV 2-27-3 and 2-30-1 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the Second Set of Data Requests issued by the Division during the pre-filing stage and then filed by the Company in the above referenced docket on December 21, 2023. The Company requests protective treatment of the Confidential Attachments in accordance with 810-RICR-00-00-1.3(H) and 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

The Confidential Attachments, which are the subject of this Motion, are 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.

The Confidential Attachments consist of system information in Pennsylvania (Attachment DIV 2-27-3) and in Rhode Island (Attachment DIV 2-30-1). The Company would customarily not release Attachment DIV 2-30-1 to the public and, for the Pennsylvania jurisdiction, the Company would customarily not release Attachment DIV 2-27-3 to the public. (Rhode Island and Kentucky consider this information public.) The Company's submission of the Confidential Attachments stem from data requests issued by the Division in the above-referenced docket. Accordingly, the Company is providing the Confidential Attachments to fulfil its regulatory responsibilities.

Public disclosure of the information identified in the Confidential Attachments may negatively impact the Company's ability to effectively operate to provide safe and reliable service to its customers in Pennsylvania and Rhode Island. As such, the Company would not release this information to the public. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

III. CONCLUSION

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

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

Dated: December 21, 2023

CERTIFICATE OF SERVICE

I hereby certify that on December 21, 2023, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 23-48-EL.

____
Joanne M. Scanlon

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

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

Rhode Island Energy™
a PPL company

November 30, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. TBD - Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 2 (Complete Set)</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's complete set of responses to the Division of Public Utilities and Carriers' ("Division's") Second Set of Data Requests in the above-referenced matter.

In this transmittal, the Company is also providing corrected responses to Division 2-2 and Division 2-17. In addition, the Company is providing a corrected Attachment DIV 2-14-6 in Excel version, which stems from the correction to Division 2-2. The Company also added Ryan Constable as a joint sponsor with Eric Wiesner to the Company's response to Division 2-23.

Please note that the Company is seeking confidential treatment of the following attachments: Attachments DIV 2-5-4 through DIV 2-5-6, Attachments DIV 2-14-1 through DIV 2-14-5; the revised Excel version of Attachment DIV 2-14-6, Attachment DIV 2-27-3; the Excel version of Attachment DIV 2-30-1, and Attachments DIV 2-31-1 through DIV 2-31-3.

The confidential version of the Company's complete set of responses to the Division's Second Set of Data Requests will be sent via a secured link and is subject to the universal Non-Disclosure Agreement between the Company and the Division.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

Division 2-1

Spare Transformers

Request:

Regarding substation spare transformers, the Company states it needs 30 spares to meet reliability criteria and that current inventory is seven spares. (FY 2025 ISR Plan, Attachment 5, starting page 111)

"In total, the Reliability Criterion Model indicates that the company will need thirty (30) spare transformers to meet a .9950 system reliability. The .9950 system reliability benchmark indicates that the company will have a spare available 99.5% of the time. This number has been cited by IEEE to be a common benchmark amongst a wide number of utilities." (page 112)

a. Provide a list of spare power transformers owned by each National Grid affiliate (New York, Massachusetts, and Rhode Island) by voltage (high and low side), capacity, and winding configuration that were available to the Company under National Grid ownership (assume a date just before PPL acquisition). Identify spare transformers that were owned by RIE and located on the Company's system.

b. Provide the same information for spare transformers available to the Company under PPL ownership indicating whether the spare is owned by RIE or another entity. Identify spare transformers that are located on the Company's system.

Response:

a. Attachment DIV-2-1-1 is a spreadsheet created by National Grid documenting the number of spare transformers located in the National Grid New England area prior to May 24, 2022. Transformers denoted as RI were assumed to belong to The Narragansett Electric Company ("NECO") and would remain with the Company post sale. There are two tabs, one is what National Grid considered transmission spares and the other shows distribution spares owned by NECO. All notes in these tables were created by National Grid.

   Attachment DIV-2-1-1 does not document spare transformers rated at or above 69kV with a capacity less than 30MVA and does not document distribution spare transformers owned by The Massachusetts Electric Company.

b. Attachment DIV-2-1-2 shows the number of in-service transformers and spare transformers by voltage class and capacity. All spares shown in this attachment are owned by RIE. There are ongoing discussions between operating companies to review system differences, logistical challenges, and regulatory requirements to allow for sharing

Spare Transformers

of assets between operating companies. Upon initial review, there are voltage differences between the various operating companies that limit the feasibility of sharing spare transformers. Regardless of the outcome of these discussions and review, the Company does not anticipate changes to the required number of spare transformers.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Attachment DIV 2-1-1

The Company provided the Excel spreadsheet of Attachment DIV 2-1-1.

				Location (if not RI)
Voltage and Rating	**Winding Configuration**	**# OF UNITS IN SERVICE**	**# of Existing Spares**	
115-13.2kV 33/44/55 LTC	Delta-Wye	20	0	
115-13.2 24/32/40 LTC	Delta-Wye	34	0	
115-34.5kV 48/64/80	Delta-Wye	1	0	
115-34.5kV 33/44/55	Wye-Wye	7	1 (115-34 55MVA)	
115-34.5kV 33/44/55	Delta-Wye	1	0	
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta	3	0	
115-34.5-13.8 24/32/40 MVA	Wye-Wye	2	0	
115-23kV 30/40/50	Delta-ZigZag	2	0	
115-23kV 30/40/50	Wye-Wye	6	1 (115-23 50MVA) 1 (115/23/13.2 75MVA- same unit as below)	(1) Whitinsville, MA
115-23-13.2kV 40/53/66	Wye-Wye-Delta	3	1 (115/23/13.2 75MVA)	
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	2		
115-11.5kV 33/44/55MVA LTC	Wye-Wye	6	2 (Both T assets)	
69-13.8kV 24/32/40 LTC	Delta-Wye	1	0	
69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta	1	0	
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	5	0	
33.6-12.470Y kV 12/16/20 MVA LTC	Delta-Wye	6	1 - 12/16/20MVA (Spare on Order - Westerly Repl)	
34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye	27	1 (34X23-13.2)	
34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag	1	0	
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	3	1 (5/6.25MVA) Note - Not counted towards total since this cannot carry full load	
34.5-4kV 6/7.5MVA LTC	Delta-Delta	1	0	
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye	4	0	
23-11.5 kV 7.5/9.375 MVA LTC	Delta-Delta	2	1 (10/12.5MVA)	
23-11.5kV 10/12.5MVA	ZigZag-Delta	2	0	
22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye	14	1 (7.5/8.4/10.5MVA)	
11.5-4.16/2.4Y kV 10.0/12.5 MVA LTC	Delta-Wye	2	1 (10/12.5MVA)	

Division 2-2 - Corrected
Spare Transformers

Request:

Provide a list of proposed spare transformer purchases by voltage (high and low side), capacity, and winding configuration.

Response:

Please see the table below for the proposed list of spare transformer purchases.

This table excludes the spare transformer (34x23-12.47kV 7.5/9.375MVA) that will be purchased under the Apponaug damage/failure work order to replace the spare transformer that was used for the transformer failure.

Corrected Response:

The Company made the following corrections to the table below. In the LTC column, the Company revised the "N" to "Y" as highlighted below.

Spare Transformer Voltage/Capacity	LTC	Winding Configuration	Quantity
115-13.2kV 33/44/55 MVA	Y	Delta-Wye	2
115-13.2 24/32/40 MVA	Y	Delta-Wye	3
115-34.5kV 48/64/80 MVA	Y	Delta-Wye	1
115-34.5kV 33/44/55 MVA	Y	Wye-Wye	1
115-34.5kV 33/44/55 MVA	Y	Delta-Wye	1
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA	Y	Wye-Wye-Delta	1
115-34.5-13.8 24/32/40 MVA	N	Wye-Wye	1
115-23kV 30/40/50 MVA	N	Delta-ZigZag	1
115Y/66.4kV–24kV 33/44/55 MVA	Y	Wye-Delta	1
69-13.8kV 24/32/40 MVA	Y	Delta-Wye	1
69-24 kV 25/33.3/46.6 MVA	Y	Wye-Delta	1
33.6-12.470Y kV 24/32/40 MVA	Y	Delta-Wye	1
34.5x23-12.47 kV 7.5/9.375 MVA	N	Delta-Wye	1
34.5-12.47kV 7.5/9.375MVA	N	Delta-ZigZag	1
34.5-11.0 kV 12/16/20 MVA	N	ZigZag-Delta	1
23.5-13.2 kV 15/20/25 MVA	Y	Delta-Wye	1
23-11.5kV 10/12.5MVA	N	ZigZag-Delta	1
22.9-4.16 kV 7.5/9.375 MVA	Y	Delta-Wye	1

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-2
Spare Transformers

Request:

Provide a list of proposed spare transformer purchases by voltage (high and low side), capacity, and winding configuration.

Response:

Please see the table below for the proposed list of spare transformer purchases.

This table excludes the spare transformer (34x23-12.47kV 7.5/9.375MVA) that will be purchased under the Apponaug damage/failure work order to replace the spare transformer that was used for the transformer failure.

Spare Transformer Voltage/Capacity	LTC	Winding Configuration	Quantity
115-13.2kV 33/44/55 MVA	Y	Delta-Wye	2
115-13.2 24/32/40 MVA	Y	Delta-Wye	3
115-34.5kV 48/64/80 MVA	N	Delta-Wye	1
115-34.5kV 33/44/55 MVA	N	Wye-Wye	1
115-34.5kV 33/44/55 MVA	N	Delta-Wye	1
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA	Y	Wye-Wye-Delta	1
115-34.5-13.8 24/32/40 MVA	N	Wye-Wye	1
115-23kV 30/40/50 MVA	N	Delta-ZigZag	1
115Y/66.4kV–24kV 33/44/55 MVA	Y	Wye-Delta	1
69-13.8kV 24/32/40 MVA	Y	Delta-Wye	1
69-24 kV 25/33.3/46.6 MVA	Y	Wye-Delta	1
33.6-12.470Y kV 24/32/40 MVA	Y	Delta-Wye	1
34.5x23-12.47 kV 7.5/9.375 MVA	N	Delta-Wye	1
34.5-12.47kV 7.5/9.375MVA	N	Delta-ZigZag	1
34.5-11.0 kV 12/16/20 MVA	N	ZigZag-Delta	1
23.5-13.2 kV 15/20/25 MVA	Y	Delta-Wye	1
23-11.5kV 10/12.5MVA	N	ZigZag-Delta	1
22.9-4.16 kV 7.5/9.375 MVA	Y	Delta-Wye	1

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-3
Spare Transformers

Request:

During the acquisition, PPL argued it would be supporting RIE as part of the acquisition and there would not be a decline in the support currently provided in Rhode Island from National Grid. Is RIE proposing a spare transformer program because the National Grid fleet is no longer available?

Response:

There are a variety of reasons why RIE is proposing a spare transformer program such as increased industry lead times, insufficient spare transformer coverage, and the National Grid fleet no longer being available. Reasons such as increased lead times and deficient spare transformer inventory levels would have resulted in an increase in spare transformer purchases irrespective of the National Grid fleet availability. In total, 15 of the proposed 23 new spare transformers would have been required even if the National Grid fleet of spare transformers were still available to RIE.

As described in other data requests, RIE is adopting a spare transformer strategy that uses a Poisson calculation to determine the spare transformer inventory levels. One input into this equation is transformer lead time. The National Grid spare transformer inventory was calculated using a 32-44 week lead time. However, the RIE spare transformer calculation is based on a three year lead time. This realistic lead time extension has increased the required inventory level of spare transformers from 20 to 32. With an existing spare transformer inventory of 9 transformers, 23 additional transformers will need to be purchased. The increased lead time is sole driver behind RIE needing to purchase eight of the 23 spare transformers.

RIE is also proposing to buy an additional seven spare transformers to ensure all in-service transformers are adequately covered for a transformer contingency. Updating the lead times in the calculation to match what National Grid was using (32-44 weeks), RIE would have had to purchase seven additional spare transformers regardless of the availability of the National Grid fleet of spare transformers. The in-service transformers that these seven spare transformers provide coverage for did not have an adequate spare transformer at National Grid. These seven transformers are in addition to the eight transformers mentioned in the previous paragraph.

Lastly, eight additional spare transformer purchases are required because the National Grid fleet of spares is unavailable. Four of these spares would have been required for both the original 32-44 week lead time and the increased three year lead time. Four spare transformer purchases are solely being driven by the increased lead times. However, these additional transformers would have been covered by the existing National Grid fleet. These eight transformers that National

Spare Transformers

Grid currently owns, and would have provided coverage to RI, were not paid for by RIE ratepayers. If RI needed to use one of these transformers, RI ratepayers would have paid the net book value, and the ownership would have changed to The Narragansett Electric Company. Therefore, the additional eight transformers that are being purchased are not duplicative costs.

PPL has instituted a centralized procurement philosophy between all PPL operating companies to achieve synergies where possible. In this respect, PPL will look to share equipment where possible (reclosers, switches, arresters, etc.). However, there are voltage differences between the operating companies which makes it difficult to adopt a common spare transformer strategy.

RIE is currently reviewing spare transformer inventory located in Pennsylvania and Kentucky along with exploring a mechanism to share common equipment between operating companies. The initial desktop review did not indicate much commonality between the transformer assets located in either operating company.

Division 2-4
Spare Transformers

Request:

Explain why a short term extended delivery schedule for power transformers should drive a large spare transformer purchasing program?

Response:

If a utility has one spare for a group of similar transformers and one transformer fails and is replaced with the spare, there is no spare until a replacement can be delivered. If there is a second failure, there will be no spare available. The longer the delivery time, the greater the risk that another transformer will fail with no spare available.

Short term extended delivery schedules can extend even further since other utilities will increase their spare transformer inventory levels based on the current power transformer lead times. Spare transformer inventory projections are proportional to transformer delivery lead times.

There is also an indication that the extended delivery schedule will persist for another 5-10 years due to other utilities replacing older transformers and with the increase in large data center installations. The Company will review power transformer lead times annually and update the spare transformer calculation accordingly. If the calculations show that the Company has an abundance of a certain type of transformer, the Company will look to use that transformer for a capital project. The Company will also structure the spare transformer procurement such that similar transformers will be purchased over multiple years. This should reduce the risk of overbuying a certain type of transformer if the lead times decrease over the next 5 years.

Division 2-5
Spare Transformers

Request:

Provide all discussions with power transformer manufactures which supports the RIE claim that a 3-year lead time applies to all transformer sizes and voltages and will continue indefinitely.

Response:

The following lead times were quoted from three transformer bidding events (40 and 55 MVA) this past summer. Please see attachments DIV-2-5-1 through DIV-2-5-6 for copies of the bid documents.

1. Pennsylvania Transformer Technology: 96 – 110 weeks ARO, 100 weeks ARO
2. Virginia Transformer Corp.: 80 – 95 weeks ARO, 75 weeks ARO
3. GE Prolec – Mexico Plant: 126 + weeks ARO, 136 weeks ARO
4. Delta Star: 140-150 weeks ARO

The latest general lead time request made November 2023:

1. Niagara Transformer: 170 – 200 weeks with no drop off in demand anticipated for the next 5 – 10 years.
2. GE-Prolec – Mexico Plant: 176 weeks: Too difficult to guess lead times 5 years from now.
3. Delta Star: 170 weeks with no drop off in demand for at least the next 7 years.

A recent request for a small size transformer (14 MVA):
Pennsylvania Transformer Technology: 78 – 82 weeks ARO

Attachment DIV-2-5-7 shows a summary of responses from transformer vendors regarding lead times and how long they expect demand to remain strong.

Note that these are delivery times After Receipt of Order (ARO). The bidding/award process typically takes 3-4 months before an order is issued.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Hopkins Hill

PPL SERVICES CORP

Proposal #: AA232701A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE–ONE COMMITMENT

Commercial Summary

Base Price

Item	Description	Qty	Unit Price (USD)	Extended Price (USD)
1	24,000 / 32,000 / 40,000 kVA | 33.6 - 12.47 kV	1		

Tax Certificates Requirement

Upon acceptance of our proposal, the purchaser is required to submit a sales tax exemption certificate with the Purchase order, otherwise VTC will charge appropriate state taxes based on the destination.

TERMS AND CONDITIONS: Unless other terms or MSA is agreed between Customer and VTC/GTC, the Proposal will be governed by VTC/GTC Standard Terms & Conditions, attached towards the end of technical Proposal or provide as Separate Document.

Price Policy

In the event of customer delay on a job quoted with a firm price and shipment date, VTC/GTC will apply the BLS Transformer Index to adjust price. The agreed firm price will be escalated with the base period being the quoted shipment date and the Settlement date being the month of shipment. Only increases in the BLS index will be considered for this calculation. Any advance payments will be credited to the final invoice. No adjustment will be applied if the transformer is completed and shipped prior to the quoted shipment date.

Validity of Quote

09/08/2023

Estimated Freight Cost

Item	Ship To	Qty	Freight Cost (USD)	Extended Freight Cost (USD)
1	Hopkins Hill Substation in West Greenwich, RI	1		

VTC will quote freight at the time of shipment.

Hopkins Hill

PPL SERVICES CORP

Proposal #: AA232701A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE–ONE COMMITMENT

ITEM #1

Optional Pricing

Particulars	Price (USD/Per Unit)
GIC Calculations	

For Witness testing, cost for travel, transportation, lodging and meals are not included in the quoted price unless otherwise noted.

Suggested Spare Parts

Particulars	Price (USD/Per Unit)
HV BUSHING - Qty 1	
LV BUSHING - Qty 1	
X0 BUSHING - Qty 1	
FAN - Qty 1	

Shipping

Unit Shipment By	70-74 Weeks from Order Acknowledgement date. VTC reserves the right to ship unit up to 3 months earlier than the contractual ship date.
Freight	PREPAID & ADD
Estimated Freight Cost (Per Unit)	
INCO Terms	DAT - DELIVERED AT TERMINAL(Hopkins Hill Substation pad in West Greenwich, RI)
Proposed Manufacturing Location	POCATELLO, ID USA
Impact Recorder	

VTC cannot guarantee multiple units to arrive at the same time unless more than one unit can be loaded on the same truck. VTC cannot guarantee arrival dates and times at the job site.
Final Lead time will be confirmed at the time of order acknowledgements

Proposed Payment Terms

DELTA STAR QUOTATION Q011824 **Date: 8/14/2023**

PPL ELECTRIC UTILITIES

Bid For:	**24/32/40 MVA Power Transformer**
Event:	**Hopkins Hill for RIE**
Bid Opening:	**August 14, 2023**
Delta Star Quotation:	**Q011824**

Helen L. Thomas
PPL Electric Utilities
2 N 9th Street
Allentown, PA 18101-1179
hlthomas@pplweb.com

Delta Star Quotation: Q011824
Revision: 0
Quotation Date: August 14, 2023

Delta Star Contacts

Regional Sales Director
Ben Abebe
babebe@deltastar.com
(724) 612-6053

Sales Representative
Zach Martin
zmartin@nexgenreps.com
(540) 521-9806

Quote Summary
Delta Star is pleased to extend our offer for the manufacture and supply of power transformer(s) as outlined below.

Shipment
Shipment is estimated at 140-150 weeks ARO subject to plant availability at time of order.

Pricing
Prices are in US dollars and do not include taxes. See Commercial Clarifications & Escalation Policy.

Quotation Validity
Quotation is valid 90 days from bid opening.

Payment Terms
Net 45

Field Service
See attached Field Service Policy and Scope of Work.

PPL
First Street Substation
05/22/23

2. SOLUTION DESCRIPTIONS AND PRICING

Item	Description	Qty.	Unit Price (USD)
1A	Three phase, oil immersed transformer, **24/32/40 MVA, ONAN/ONAF/ONAF**, 60 Hz, 65°C temperature rise, high voltage of **115 kV Delta** connection with No Load Tap Changer and low voltage of **13.2 kV Wye** connection with Load Tap Changer. - We are quoting these transformers EX Works (Incoterms 2010) Factory in Apodaca, N.L. México. Refer to section 5.4. - Dry air shipment	1	
1A.T	Unit price adder for transportation from **Factory** to deliver this transformer CIF (Incoterms 2010) at **51 First Street, East Providence, Rhode Island 02914** Buyer shall provide, at its own expense, free and clear access to PGE and PGE's subcontractors for purposes of inspecting access routes to the delivery pad (if applicable). If such access is not allowed within thirty (30) days after execution or expedition of a binding Purchase Order, the quoted freight price shall be subject to applicable extra costs as necessary, according to PGE's subcontractor's inspections. Should PGE or its subcontractor deem it necessary to make modifications to access routes, or to use special equipment or maneuvers in order to perform proper delivery, Buyer shall make such modifications and/or bear the costs for any special equipment or maneuvers to be used. Upon arrival by GE Prolec or GE Prolec's subcontractors in charge of freight for delivery, the Purchaser shall promptly begin the applicable actions in order for proper delivery and reception to take place. If such actions are not started within 24 hours after arrival of the Products, the Purchaser shall hold GE Prolec harmless from and against any and all costs which GE Prolec might incur by reason of such delay, including but not limited to demurrage costs.	1	
1A.R	Unit price adder for off-loading and place on pad. For truck shipment. Price is considering delivery address in: **51 First Street, East Providence, Rhode Island 02914**	1	
1A.FES	Price Adder for a field engineer supervision for field installation. Refer to section 5.2 for more details.	1	

5.2 Technical supervision

N/A

5.3 Validity Period

This proposal will remain valid for a period of **30 days** after submittal.

5.4 Delivery Terms

5.4.1. Shipment

Our standard shipping estimate is **136 – 140 weeks** after receipt of an order, which includes print approval. Our standard approval drawings will be mailed **30 – 34 weeks** after receipt of the order. GE Prolec timing includes a customer review period of two (2) weeks including mailing time.

Actual shipment and drawing schedules will depend on factory backlog at the time of the purchase order acceptance. Shipment dates are approximate and are based upon prompt receipt of all necessary information from PPL. Please contact the Factory if a shorter cycle is required.

The shipment estimate indicated above includes customer witness visits. The Project Manager will inform PPL ten (10) days prior to specified dates for test witnessing. GE Prolec will perform the final test set and prepare for shipment and on-time delivery per contractual requirements, with or without confirmation of notification from customer. GE Prolec will submit a certified test report to PPL.

The seller will determine point of origin of shipment, method of transportation, carrier and routing to the port described above.

If customer decides to buy the shipping option offered in Section 2, we will deliver these transformers DDP (INCOTERMS 2010) with freight allowed to common carrier delivery point nearest the final destination: **51 First Street, East Providence, Rhode Island 02914.** Title Transfer and Risk of Loss will be transferred to PPL on **DDP** point.

If PPL specifies a manner or routing of shipment different from that determined by Seller, any additional expenses will be borne by PPL.

PPL shall bear complete responsibility for off-loading, any transportation beyond the delivery point, and installation of the transformer at the job site, unless PPL chooses to purchase these options proposed on **Section 2** of this proposal.

Disclaimer for Transportation

If the transformer is subjected to impacts during transportation, the Seller reserves the right to assess/evaluate any potential damage by visual inspection and field tests including, but not limited to, megger, ratio, power factor and FRA. No single test, by itself, will be used to reach a conclusion.

Nasonville

PPL SERVICES CORP

Proposal #: AA230401A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE-ONE COMMITMENT

Commercial Summary

Base Price

Item	Description	Qty	Unit Price (USD)	Extended Price (USD)
1	33,000 / 44,000 / 55,000 kVA | 115 - 13.8 kV	1	[redacted]	[redacted]

Tax Certificates Requirement

Upon acceptance of our proposal, the purchaser is required to submit a sales tax exemption certificate with the Purchase order, otherwise VTC will charge appropriate state taxes based on the destination.

Price Policy

In the event of customer delay on a job quoted with a firm price and shipment date, VTC/GTC will apply the BLS Transformer Index to adjust price. The agreed firm price will be escalated with the base period being the quoted shipment date and the Settlement date being the month of shipment. Only increases in the BLS index will be considered for this calculation. Any advance payments will be credited to the final invoice. No adjustment will be applied if the transformer is completed and shipped prior to the quoted shipment date.

Validity of Quote

07/26/2023

Nasonville

PPL SERVICES CORP

Proposal #: AA230401A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE–ONE COMMITMENT

ITEM #1

Optional Pricing

Particulars	Price (USD/Per Unit)
Field Service Offload to Pad - Requires free & clear access	[redacted]
Field Service Assembly & Testing with SFRA	[redacted]
Price Deduct for Item 1 as a Non-LTC Design	[redacted]

For Witness testing, cost for travel, transportation, lodging and meals are not included in the quoted price unless otherwise noted.

Suggested Spare Parts

Particulars	Price (USD/Per Unit)
HV BUSHING - Qty 1	[redacted]
LV BUSHING - Qty 1	
X0 BUSHING - Qty 1	
FAN - Qty 1	
GASKET SET - Qty 1	

Shipping

Unit Shipment By	70-75 Weeks from Order Acknowledgement date. VTC reserves the right to ship unit up to 3 months earlier than the contractual ship date.
Freight	PREPAID & ADD
INCO Terms	EXW - EX WORKS - POCATELLO, ID USA
Proposed Manufacturing Location	POCATELLO, ID USA
Impact Recorder	Impact Recorder to be provided on Returnable Basis, [redacted] to be invoiced if not returned in 30 days after Delivery.

VTC cannot guarantee multiple units to arrive at the same time unless more than one unit can be loaded on the same truck. VTC cannot guarantee arrival dates and times at the job site.
Final Lead time will be confirmed at the time of order acknowledgements

Proposed Payment Terms

PRICE AND DELIVERY

1. PRICE

ITEM	QTY	MVA	PHASE	HZ	VOLTAGE	PRICE EACH (USD)
1B	1	33/44/55 ONAF/ONAF/ONAF	3	60	115Δ-13.8Y kV Very Low Sound	[redacted]
1C	1	Assemble/Fill/Test			Adder	[redacted]

* A service engineer for supervision/informal (non-classroom) training will be provided per the rate sheet attached.

* Parts required for energization are included in the base bid. Price does not include spare parts beyond this. See attached list for adders.

2. FREIGHT AND FOB TERMS

The quoted price is for delivery of the specified equipment F.O.B. Pad via RAIL/TRUCK with freight prepaid to Harrisville, RI. **Unloading and local hauling are included. Assembly, vacuum filling, and field testing are not included in the base price (see above adder). As unloading onto pad is included, PTTI assumes free and complete access to the pad.**

NOTE: Truck shipment to destination is limited to sites that are accessible by the vehicle in which the unit is shipped from the factory. Seller assumes no liabilities for any structures that require relocation or reinforcement in order to reach said destination.

3. SHIPPING DETAILS (Qualification to RFQ)

Radiators, arresters, arrester brackets, and bushings will be removed for shipment. The unit will be sealed with a positive pressure of dry air for shipment. If oil is included in this contract, it will be delivered to the jobsite via tank truck. PTTI will not be responsible for demurrage charges after 2 hours. Oil has to be off-loaded within 2 hours of delivery. In case of delays, a detention of $120/hour will apply.

4. SHIPPING SCHEDULE (Exception to RFQ)

The proposed transformer will be scheduled to ship 96-100 weeks or sooner after receipt of a purchase order subject to prior sale. Unit will be manufactured at Canonsburg, PA factory.

PPL
RI Energy Nasonville Transformer

07/07/23

2. SOLUTION DESCRIPTIONS AND PRICING

Item	Description	Qty.	Unit Price (USD)
1B	Three phase, oil immersed transformer, **33/44/55 MVA, ONAN/ONAF/ONAF**, 60 Hz, 65°C temperature rise, high voltage of **115 kV Delta** connection with No Load Tap Changer and low voltage of **13.8 kV Wye** connection with Load Tap Changer. - We are quoting these transformers EX Works (Incoterms 2010) Factory in Apodaca, N.L. México. Refer to section 5.4. - Dry air shipment	1	[redacted]
1B.T	Unit price adder for transportation from **Factory** to deliver this transformer CIF (Incoterms 2010) at **NasonVille Substation - 445 Douglas Turnpike, Harrisville, Rhode Island, 02830.** Buyer shall provide, at its own expense, free and clear access to PGE and PGE's subcontractors for purposes of inspecting access routes to the delivery pad (if applicable). If such access is not allowed within thirty (30) days after execution or expedition of a binding Purchase Order, the quoted freight price shall be subject to applicable extra costs as necessary, according to PGE's subcontractor's inspections. Should PGE or its subcontractor deem it necessary to make modifications to access routes, or to use special equipment or maneuvers in order to perform proper delivery, Buyer shall make such modifications and/or bear the costs for any special equipment or maneuvers to be used. Upon arrival by GE Prolec or GE Prolec's subcontractors in charge of freight for delivery, the Purchaser shall promptly begin the applicable actions in order for proper delivery and reception to take place. If such actions are not started within 24 hours after arrival of the Products, the Purchaser shall hold GE Prolec harmless from and against any and all costs which GE Prolec might incur by reason of such delay, including but not limited to demurrage costs.	1	[redacted]
1B.R	Unit Price adder for heavy hauling from the rail siding to the final destination and off-loading to the substation pad. Price is considering delivery address: **NasonVille Substation - 445 Douglas Turnpike, Harrisville, Rhode Island, 02830.**	1	[redacted]
1B.FES	Price Adder for a field engineer supervision for field installation. Refer to section 5.2 for more details.	1	[redacted]

5.1 Installation Services

Please refer to Exhibit E - Installation Services Proposal.

5.2 Technical supervision

N/A

5.3 Validity Period

This proposal will remain valid for a period of **30 days** after submittal.

5.4 Delivery Terms

5.4.1. Shipment

Our standard shipping estimate is **2Q 2026** after receipt of an order, which includes print approval. Our standard approval drawings will be mailed **30-34 weeks** after receipt of the order. GE Prolec timing includes a customer review period of two (2) weeks including mailing time.

Actual shipment and drawing schedules will depend on factory backlog at the time of the purchase order acceptance. Shipment dates are approximate and are based upon prompt receipt of all necessary information from PPL. Please contact the Factory if a shorter cycle is required.

The shipment estimate indicated above includes customer witness visits. The Project Manager will inform PPL ten (10) days prior to specified dates for test witnessing. GE Prolec will perform the final test set and prepare for shipment and on-time delivery per contractual requirements, with or without confirmation of notification from customer. GE Prolec will submit a certified test report to PPL.

The seller will determine point of origin of shipment, method of transportation, carrier and routing to the port described above.

If customer decides to buy the shipping option offered in Section 2, we will deliver these transformers DDP (INCOTERMS 2010) with freight allowed to common carrier delivery point nearest the final destination: **NasonVille Substation: 445 Douglas Turnpike, Harrisville, Rhode Island, 02830.** Title Transfer and Risk of Loss will be transferred to PPL on **DDP** point.

If PPL specifies a manner or routing of shipment different from that determined by Seller, any additional expenses will be borne by PPL.

PPL shall bear complete responsibility for off-loading, any transportation beyond the delivery point, and installation of the transformer at the job site, unless PPL chooses to purchase these options proposed on **Section 2** of this proposal.

Waukesha/ GE Prolec:
Waukesha is quoting 2028 for alliance customers. Currently, PPL is not an alliance customer – if PPL wants us to hold any slots for transformers, let me know… I'll see what I can do for them in 2028 or 2029.

Monterrey: Currently, the proposals come out as 2027 – Q1 or Q2.

Canoas (Brazil): Currently, the proposals come out as 2026 – Q1 or Q2.

SMIT:
Helen, we're hearing directly from some of the largest US IOUs that their EHV (345kV & up) needs will continue into 2030!
Data centers are driving part of this need but mostly it is still replacement of older units.

For Smit, transformers, reactors or phase shifters don't make a difference with lead times, which currently are **Q1 2028 ex-works**.

PTTI:
10-20MVA (34.5kV-12kV) sizes would be built in our Raeford, NC facility whose lead times are currently 78-82 weeks ARO. Yes, we expect demand to remain strong for 5-10 years.

Division 2-6
Spare Transformers

Request:

What is the power transformer manufacturer's projection for delivery schedules 5 years from now?

Response:

One transformer manufacturer stated that they expect the demand to remain strong for 5 – 10 years. Another transformer manufacturer does not see the demand to drop off for at least the next 7 years. Another transformer manufacturer stated that it is too difficult to guess lead times 5 years from now.

Many manufactures are hesitant to provide specific long-term projected delivery schedules due to material/labor force shortages and unpredictable growth in transitioning away from fossil fuels.

PPL procurement does not see significant reductions in the lead times of transformers. This is driven in part by the predicted increased requirements that the nationwide shift to electrified heating and transportation will put on electric utilities.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-7
Spare Transformers

Request:

What is RIE's estimate for power transformer failures over the next five years?

Response:

RIE's expected failure rate is 0.5%. Using this value, along with the number of transformers expected to be in service, the company estimates that approximately 3-4 transformers will fail over the next 5 years.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-8
Spare Transformers

Request:

How many power transformers have failed each year for the past 10 years?

Response:

Please see the table below showing the number of power transformer failures for the past 10 years.

Fiscal Year	# of failed transformers	Substation(s)
2015	1	Warwick Mall (T2)
2016	1	Valley (22T)
2017	0	
2018	1	Hospital (T462)
2019	2	Westerly (T4), Sockanosett (T1)
2020	0	---
2021	0	---
2022	1	Westerly (T2)
2023	1	Hopkins Hill (T2)
2024	2	Sprague St (T2), Apponaug (T4)

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-9
Spare Transformers

Request:

In the past ten years, how many times has the Company called upon a spare transformer from Massachusetts or New York to be utilized in Rhode Island?

Response:

As indicated in the response to Division 2-8, there were nine transformer failures in the past 10 years. In two cases, spare transformers from Massachusetts were used. New units were ordered for two additional failures while mobile substations were installed. One transformer was rewound, and the tank re-used. Four failures were covered by Rhode Island-owned spare transformers.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-10
Spare Transformers

Request:

In the past ten years, how many times has a spare transformer owned by the Company been called upon to be utilized in New York or Massachusetts?

Response:

A data request has been sent to National Grid, and RIE is still waiting for a response. The Company will supplement the response if and when we receive the data from National Grid.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-11
Spare Transformers

Request:

Provide a copy of the Company's guidelines used to determine the desired number and types of spare transformers under National Grid ownership. Provide a copy of the current guidelines.

Response:

- National Grid Philosophy: Please see Attachment DIV 2-11.

- PPL Philosophy: RIE will use a Poisson probability distribution (Minimum Reliability Criterion Model) to calculate the number of spare transformers needed for each transformer grouping based on voltage and capacity. This calculation is based on the number of in-service transformers, the average transformer failure rate, and the transformer lead time. The average failure rate and lead time used in these calculations will be .5% and three years respectively. The calculated spare transformer quantities will establish the minimum number of spare transformers needed to achieve a minimum reliability of .9950. This metric indicates that, if the identified number of spare transformers are purchased, there is a 99.5% probability that the utility will have a spare transformer available. Without a spare transformer being available, the utility will need to install a mobile transformer, or have the system in an abnormal configuration, for three years while a new substation transformer is being built.

A formal document summarizing the PPL Operating Companies spare transformer philosophy is being developed and will be published after approval from all 3 operating companies. RIE leadership has approved the need for the requested transformers in this filing, regardless of the outcome of the ongoing review.

INTRODUCTION

This policy establishes a framework by which National Grid identifies and manages Spare Equipment on the Transmission and Distribution System. Spare Equipment is required to ensure a timely restoration of service in the event of a failure or emergency.

PURPOSE

Equipment specific spare strategies will be created based on the framework of this document.

Surplus equipment deemed obsolete or in poor repair/condition shall not be considered during the review of Spare Equipment. Reviews of spare equipment stores, and locations will be performed alongside a review of this standard.

ACCOUNTABILITY

Substation Engineering

COORDINATION

Substation Engineering (Substation O&M Services)
Transmission Planning & Asset Management
Distribution Planning & Asset Management
National Grid Procurement

REFERENCES

SMS 401.10.02 Circuit Breaker Long Term Storage
SMS 402.08.02 Transformer Long-Term Storage Procedure

DEFINITIONS

Spare - Equipment is not in operation and is a possible replacement. Spares can be a 1-to-1, which is an assurance spare, or 1-to-many

TRAINING

Not Applicable.

DOCUMENT CONTENTS

Table of Contents

1.0 IDENTIFYING NEED

1.1 The process of identifying and securing spare equipment will be determined by the following factors:

1.1.1 A periodic survey will be done once a year to determine how many units, of a particular type, voltage class, capacity and other pertinent factors, are in service and compared to the available Spare Equipment. This will be achieved through a Poisson analysis of the units and stored on the Substation Equipment and Commissioning Engineering SharePoint. The units referenced in the Poisson analysis are deemed strategic spares or have stores codes already associated with them.

1.1.2 To minimize the level of future spare holding requirements the equipment specific strategies will take into account the spares requirements for a given asset type across all of the National Grid businesses. This shall entail the spares holding of one business being utilized by another at times. Technical and regulatory factors may determine these transfers are not permanent in nature.

1.1.3 Should the establishment of new spares holding requirement result in significant costs, consideration should be given to phasing in the spares holding requirements over time.

1.1.4 Consideration should be given to the procurement of spare equipment for specific equipment identified that as critical, strategic items of plant, or a component of a sensitive customer connection.

1.1.5 To minimize the level of spare equipment, design principles should encourage interchangeability of equipment being added to the system to limit the equipment types.

1.1.6 In determining spare equipment levels, consideration should be given to the design life expectancy of the assets, manufacturer support, failure rates, and any known performance issues of a particular class of equipment.

a. When performing the spare review consideration must be given to certain equipment, which may be unique, and having a relatively small quantity in service, but are critical to the System and/or have exceptionally long lead times

1.1.7 In general, as a piece of equipment is used to replace a failed unit, the need for an additional spare will be confirmed and a new one re-ordered immediately on the appropriate Damage and Failure Project.

a. Substation Spare Transformers shall be re-ordered immediately and shall not be lumped into other orders that are part of a global event or bid strategies.

1.1.8 Quantities of required spares and re-order points will be determined by Substation O&M Services

2.0 STORAGE, MONITORING AND COMPLIANCE

2.1 Storage location and identification

2.1.1 Once a decision has been made as to the quantity of a particular class of equipment, the storage location should be determined based on the locations of in-service units, system access, and the availability of delivery services.

2.1.2 Each piece of spare equipment will be identified with a National Grid Equipment Reference Number which will be tracked through CMMS (Computerized Maintenance Management System). Spare Equipment classified as a Strategic Spare will also be identified with a National Grid Equipment Reference Number which will be tracked by CMMS (Computerized Maintenance Management System) and Power Plant.

2.1.3 Equipment decommissioned due to upgrades, or other reasons, will be evaluated to determine whether the equipment is acceptable for use as a spare or should be scrapped.

2.1.4 Equipment will only be considered decommissioned and put in the CMMS DECOM System when it has been removed from National Grid Property.

a. Until it is removed it will be listed in CMMS in an operating position with a description that starts with OOS (out of service) followed by its former Control Center designation.

b. Decommissioned equipment will be permanently listed in the CMMS DECOM System in special operating positions broken down by year and type of equipment.

2.1.5 Dummy operating positions may be created in a location to store spare equipment.

a. These operating positions will have a description of Spare Breaker, Spare Regulators, and Spare Transformer etc. The classification of Strategic Spare will be assigned if so determined.

2.1.6 Operating positions that are no longer in service but could at some time be returned to service will retain their operating position description prefixed with OOS.

a. Operating positions that are no longer in service, and never will never be returned to service, will be permanently listed in only in the CMMS DECOM System in their original region.

2.2 Equipment turnover

2.2.1 If possible, strategic or spare equipment will be cycled through the construction process to ensure a piece of equipment is not inactive for long periods of time. Attempts should be made to rotate spare equipment to in-service positions within their warranty periods.

2.2.2 Substation Engineering will be responsible for cycling equipment through the System. As projects come through that use up the spares from Cascade, Substation Engineering will be in charge of noting the change in cascade.

2.2.3 When Spare Equipment is used in an emergency, the Division requiring the equipment shall notify Substation O&M Services as soon as possible to ensure the CMMS data is updated and the equipment is replaced following the Substation Work Order Summary process.

2.3 Annual Reconciliation of Strategic Spares

2.3.1 As required, a reconciliation of Spare Equipment with the classification of Strategic Spares will be conducted by Substation O&M Services to ensure an accurate accounting between Power Plant and CMMS (Computerized Maintenance Management System).

2.3.2 Exceptions to the report must be reconciled upon finding

2.4 Maintaining Equipment Condition

2.4.1 Spare equipment will be maintained in a condition ready for service.

2.4.2 All transformer bushings and surge arresters should be bonded together and connected to the transformer tank or system ground.

2.4.3 Heaters, alarms, AC/DC power will be provided where necessary and visually inspected on a bimonthly interval by the responsible Local Maintenance & Construction Department in the area where the equipment is stored. This will be done in accordance with SMP 401.10.02 & SMP 402.08.02.

2.4.4 Budget Responsibility

2.5 Spare Equipment, not set as stores items, will be funded centrally by the respective business function responsible for the asset class. The respective business function will also be responsible for the Maintenance & Construction carrying costs associated with the spare.

3.0 RULES FOR CAPITALIZATION OF SPARE EQUIPMENT

3.1 Equipment items designed for a specific physical location, requiring long lead times to acquire, and characterized by material costs in excess of $25,000 will be allowed to be capitalized whether they are physically in service or held in reserve.

3.2 Criteria for identifying Strategic Spares

3.2.1 Twenty (20) years or newer

3.2.2 Purchased value of $25,000 or more

3.2.3 23kV or higher and above criteria

3.2.4 New Transformers

3.3 Spare equipment that does not meet the above criteria will be set-up as a stores item to be readily available in the event of failure, construction etc. When these items are issued from stores, a specific project, work order and location is required.

4.0 REVIEW AND APPROVAL

4.1 This policy is written and maintained by Substation O&M Services Engineers. Questions regarding its content and application should be addressed to the Manager of Substation Equipment & Commissioning Engineers.

4.2 Substation Equipment & Commissioning Engineers shall be responsible for the review and the ongoing appropriateness of this policy and amendments to it. A review of the spares in stock shall be performed each year.

5.0 REVISION HISTORY

Version	Date	Description of Revision
0.0	xx/xx/xx	Initial version of document.
1.0	12/26/06	Corrected - Formatting Changed - Header title, Document number prefix Changed - First page footer to reference Documentum Changed - Document title (removed "Policy") Removed – Subtitle
1.1	04/06/07	Header - Minor formatting change
1.2	05/02/07	Storage, Monitoring and Compliance Added - Equipment will only be considered decommissioned……………. Added - Dummy operating positions may be created……………. Added - Operating positions that are no longer in service……………. Added - Spare Parts
1.3	05/23/07	Document Added - Documentum Version # to headers Added - File name to footer
1.4	01/17/08	Storage, Monitoring and Compliance - Maintaining Equipment Condition Added - All transformer bushings and surge arresters should be bonded together and connected to the transformer tank or system ground.
1.5	10/06/08	V 1.5 - Added section 2.3 and updated document based on Strategic Spares – US Review Report No. 0361 for annual reconciliation of strategic spares between Power Plant and the Asset Information & Maintenance Management System.
1.6	07/19/22	Updated originating department from “Substation T&D Services” to “NE/NY Substation O&M Services”. Updated sponsor from “David Ethier” to “James McGrath / Peter Altenburger”. Updated department name to “Substation O&M Services” throughout document.

Version	Date	Description of Revision
1.0	08/31/12	Converted to new format Document Number - Changed “SMS 400.12.1” to “SMS 400.20.1” Originating Department - Changed “Substation O&M Services” to “Substation Work Methods” Sponsor - Changed “Donald T. Angell” to “Susan Fleck” Purpose - Changed “…poor repair/condition will not be considered …” to “…poor repair/condition shall not be considered …” Definitions - Added “Spare” Section 1.1.2 - Changed “... across all of the National Grid USA businesses. This will entail the spares …” to “… across all of the National Grid businesses. This shall entail the spares …” Section 1.1.9 - Changed “… determined by O&M Services.” to “… determined by Substation Work Methods and Electric Material Standards.” Section 2.1.2 - Changed “…through the Asset Information & Maintenance Management System. … in the Asset Information System and Power Plant AIMMS” to “…through CMMS (Computerized Maintenance Management System). … in CMMS (Computerized Maintenance Management System) and Power Plant.” Section 2.1.4 - Changed “…put in the AIMMS DECOM …” to “…put in the CMMS DECOM …” Section 2.1.4.a - Changed “…will be listed in AIMMS in an …” to “…will be listed in CMMS in an …’ Section 2.1.4.b - Changed “…in the AIMMS DECOM …” to “…in the CMMS DECOM …” Section 2.1.6.a - Changed “…in the AIMMS DECOM …” to “…in the CMMS DECOM …” Section 2.2.2 - Changed “Substation O&M Services …” to “Substation Work Methods …” Section 2.2.3 “…equipment should notify O&M Services as soon as possible to ensure the AIMMS data is … to “…equipment shall notify Substation Work Methods as soon as possible to ensure the CMMS data is …” Section 2.3.1 - Changed “…conducted by Substation O&M Services to ensure an accurate accounting between Power Plant and the Asset Information & Maintenance Management System.” to “…conducted by both Electric Material Standards and Substation Work Methods to ensure an accurate accounting between Power Plant and CMMS (Computerized Maintenance Management System).” Section 2.4.3 - Changed “…the responsible O&M department in …” to “…the responsible Local Maintenance & Construction Department in …” Section 3.1 - Changed “… responsible for the O&M carrying costs …” to “… responsible for the Maintenance & Construction carrying costs …” Section 5.1 - Changed “…maintained by Substation O&M Services. Questions regarding its content and application should be addressed to the Manager of O&M Services.” to “… maintained by both Substation Work Methods and Electric Material Standards. Questions regarding its content and application should be addressed to the Manager of Substation Work Methods. Section 5.2 - Changed “Substation O&M Services will …” to “Both Substation Work Methods and Electric Material Standards shall …”
1.1	02/12/16	Document reviewed and updated per 3 year review cycle Originating Department - Changed “Substation Work Methods” to “Substation O&M Services” Sponsor - Changed “Susan Fleck” to “Suzan E. Martuscello” Document - Removed “Electric Material Standards’ throughout the document Document - Changed “Substation Work Methods” to “Substation O&M Services” throughout the document

Version	Date	Description of Revision
1.2	03/11/16	Document updated due to a change in process for ordering replacement spare units used for damage failures or project requirements Coordination - Replaced Section 1.1.1 - Changed “An annual survey will be done …” to “A periodic survey will be done …” Section 1.1.6 - Changed “… given to the age of the assets …” to “… given to the design life expectancy of the assets …” Section 1.1.8.a - Added and re-numbered accordingly Section 2.2.3 - Changed “… the equipment is replaced.” to “… the equipment is replaced following the Substation Work Order Summary process.” Section 2.3.1 - Changed “An annual reconciliation of …” to “As required, a reconciliation …”
2.0	01/23/23	Document updated for change of policy and procedure Section 1.1.1-reworded to encompass a one-year review process of the Poisson analysis for equipment. Section 2.2.2- Added Substation Engineering as primary for maintaining Cascades Spare list and location Removed section 2.5 Section 5- Replaced Substation O&M services with Substation Equipment & Commissioning Engineers. Added line stating that a review of the spare stores will be performed each year

Division 2-12
Spare Transformers

Request:

Provide the IEEE reference for the statement: "The .9950 system reliability benchmark indicates that the company will have a spare available 99.5% of the time. This number has been cited by IEEE to be a common benchmark amongst a wide number of utilities." (page 112)

Response:

Please see the reference below. The statement can be found on page 446.

Chowdhury, Ali, and Don Koval. Power Distribution System Reliability – Practical Methods and Applications. John Wiley & Sons, Inc, 2009.

Division 2-13
Spare Transformers

Request:

Provide all workpapers and assumptions, in executable format, used to determine the need for 30 spare transformers.

Response:

The Poisson calculation indicated a need for 32 spare transformers in the RIE inventory, 29 Distribution, 2 Transmission, and 1 Replacement for Apponaug which is also considered Distribution. The Company already has 9 spare transformers in inventory, 8 Distribution and 1 Transmission. The Company will need to procure an additional 23 spare transformers to meet the calculated inventory level of 32. Under the distribution Substation Spare Transformer program, the Company will purchase 21 of the 23 transformers, one transformer will be purchased under the Apponaug substation transformer failure project, and one transformer will be purchased under a transmission project.

Attachment DIV 2-13 provides the Poisson calculation along with an inventory of the in-service transformers less the transformers scheduled to be retired or replaced in the next 5-years.

The variables that are used in the Poisson calculation have been determined by past practice, observed failure rates, and published documents.

Two reference documents that were used to establish the Poisson calculation can be found below:

1. Chowdhury, Ali, and Don Koval. Power Distribution System Reliability – Practical Methods and Applications. John Wiley & Sons, Inc, 2009.

2. Hernandez, Ronald, Benjamin Hancock, and Manuel Salmeron. Lessons Learned from Analysis of Power Transformer Failure Rates. Doble Engineering Company, 2022.

Division 2-13, page 2

The Company provided the Excel version of Attachment DIV 2-13.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-14
Spare Transformers

Request:

Provide all workpapers and assumptions, in executable format, used to determine the proposed annual budgets for spare transformers totaling over $40 million from FY 2025 to FY 2031.

Response:

The proposed annual budgets were based off recent (2020-2023) transformer bid events and purchase orders in Rhode Island and Kentucky. Transformer technical specifications differ between the two operating companies, which causes the transformer costs to vary. Therefore, where no estimates were available for Rhode Island transformers, cost estimates from transformers in Kentucky were used as a baseline, and cost adders were used to adjust for the cost increase due to the technical specification differences.

Recent transformer costs weren't available for all transformer groupings; therefore, the Company used older costs (pre-2020) and adjusted the price to reflect the assumed cost increase if ordering a new transformer today.

These estimated costs do not reflect site work such as oil containment, foundation installation, conduit installation, or electrical wiring.

Costs for transformers are volatile and it is expected that these costs will increase or decrease over time. Therefore, the Company will evaluate the market rates annually and update the estimated costs before each ISR submittal.

As indicated in the response to Division 2-13, the Poisson calculation shows that RIE will need to purchase an additional 23 spare transformers to meet the inventory requirements. However, one spare transformer is considered a transmission asset, and one spare transformer will be purchased under the Apponaug substation transformer failure work order. Therefore, the proposed spare transformer budget accounts for purchasing 21 additional spare transformers.

Please see Attachments DIV 2-14-1 through DIV 2-14-5 for recent power transformer proposals, and DIV 2-14-6 for historical transformer costs and the calculation used to determine the estimate.

PRICE AND DELIVERY

1. PRICE

ITEM	QTY	MVA	PHASE	HZ	VOLTAGE	PRICE EACH (USD)
1B	1	33/44/55 ONAN/ONAF/ONAF	3	60	115Δ-13.8Y kV Very Low Sound	[redacted]
1C	1	Assemble/Fill/Test			Adder	[redacted]

* A service engineer for supervision/informal (non-classroom) training will be provided per the rate sheet attached.
* Parts required for energization are included in the base bid. Price does not include spare parts beyond this. See attached list for adders.

2. FREIGHT AND FOB TERMS

The quoted price is for delivery of the specified equipment F.O.B. Pad via RAIL/TRUCK with freight prepaid to Harrisville, RI. **Unloading and local hauling are included. Assembly, vacuum filling, and field testing are not included in the base price (see above adder). As unloading onto pad is included, PTTI assumes free and complete access to the pad.**

NOTE: Truck shipment to destination is limited to sites that are accessible by the vehicle in which the unit is shipped from the factory. Seller assumes no liabilities for any structures that require relocation or reinforcement in order to reach said destination.

3. SHIPPING DETAILS (Qualification to RFQ)

Radiators, arresters, arrester brackets, and bushings will be removed for shipment. The unit will be sealed with a positive pressure of dry air for shipment. If oil is included in this contract, it will be delivered to the jobsite via tank truck. PTTI will not be responsible for demurrage charges after 2 hours. Oil has to be off-loaded within 2 hours of delivery. In case of delays, a detention of $120/hour will apply.

4. SHIPPING SCHEDULE (Exception to RFQ)

The proposed transformer will be scheduled to ship [redacted] after receipt of a purchase order subject to prior sale. Unit will be manufactured at Canonsburg, PA factory.

Hopkins Hill

PPL SERVICES CORP

Proposal #: AA232701A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE–ONE COMMITMENT

Commercial Summary

Base Price

Item	Description	Qty	Unit Price (USD)	Extended Price (USD)
1	24,000 / 32,000 / 40,000 kVA | 33.6 - 12.47 kV	1	[redacted]	[redacted]

Tax Certificates Requirement

Upon acceptance of our proposal, the purchaser is required to submit a sales tax exemption certificate with the Purchase order, otherwise VTC will charge appropriate state taxes based on the destination.

TERMS AND CONDITIONS: Unless other terms or MSA is agreed between Customer and VTC/GTC, the Proposal will be governed by VTC/GTC Standard Terms & Conditions, attached towards the end of technical Proposal or provide as Separate Document.

Price Policy

In the event of customer delay on a job quoted with a firm price and shipment date, VTC/GTC will apply the BLS Transformer Index to adjust price. The agreed firm price will be escalated with the base period being the quoted shipment date and the Settlement date being the month of shipment. Only increases in the BLS index will be considered for this calculation. Any advance payments will be credited to the final invoice. No adjustment will be applied if the transformer is completed and shipped prior to the quoted shipment date.

Validity of Quote

09/08/2023

Estimated Freight Cost

Item	Ship To	Qty	Freight Cost (USD)	Extended Freight Cost (USD)
1	Hopkins Hill Substation in West Greenwich, RI	1	[redacted]	[redacted]

VTC will quote freight at the time of shipment.

REDACTED

Nasonville

PPL SERVICES CORP

Proposal #: AA230401A

VIRGINIA - GEORGIA TRANSFORMER
ONE SOURCE–ONE COMMITMENT

Commercial Summary

Base Price

Item	Description	Qty	Unit Price (USD)	Extended Price (USD)
1	33,000 / 44,000 / 55,000 kVA | 115 - 13.8 kV	1	[redacted]	[redacted]

Tax Certificates Requirement

Upon acceptance of our proposal, the purchaser is required to submit a sales tax exemption certificate with the Purchase order, otherwise VTC will charge appropriate state taxes based on the destination.

Price Policy

In the event of customer delay on a job quoted with a firm price and shipment date, VTC/GTC will apply the BLS Transformer Index to adjust price. The agreed firm price will be escalated with the base period being the quoted shipment date and the Settlement date being the month of shipment. Only increases in the BLS index will be considered for this calculation. Any advance payments will be credited to the final invoice. No adjustment will be applied if the transformer is completed and shipped prior to the quoted shipment date.

Validity of Quote

07/26/2023

PPL
First Street Substation
05/22/23

2. SOLUTION DESCRIPTIONS AND PRICING

Item	Description	Qty.	Unit Price (USD)
1A	Three phase, oil immersed transformer, **24/32/40 MVA, ONAN/ONAF/ONAF**, 60 Hz, 65°C temperature rise, high voltage of **115 kV Delta** connection with No Load Tap Changer and low voltage of **13.2 kV Wye** connection with Load Tap Changer. - We are quoting these transformers EX Works (Incoterms 2010) Factory in Apodaca, N.L. México. Refer to section 5.4. - Dry air shipment	1	$[redacted]
1A.T	Unit price adder for transportation from **Factory** to deliver this transformer CIF (Incoterms 2010) at **51 First Street, East Providence, Rhode Island 02914** Buyer shall provide, at its own expense, free and clear access to PGE and PGE's subcontractors for purposes of inspecting access routes to the delivery pad (if applicable). If such access is not allowed within thirty (30) days after execution or expedition of a binding Purchase Order, the quoted freight price shall be subject to applicable extra costs as necessary, according to PGE's subcontractor's inspections. Should PGE or its subcontractor deem it necessary to make modifications to access routes, or to use special equipment or maneuvers in order to perform proper delivery, Buyer shall make such modifications and/or bear the costs for any special equipment or maneuvers to be used. Upon arrival by GE Prolec or GE Prolec's subcontractors in charge of freight for delivery, the Purchaser shall promptly begin the applicable actions in order for proper delivery and reception to take place. If such actions are not started within 24 hours after arrival of the Products, the Purchaser shall hold GE Prolec harmless from and against any and all costs which GE Prolec might incur by reason of such delay, including but not limited to demurrage costs.	1	$ [redacted]
1A.R	Unit price adder for off-loading and place on pad. For truck shipment. Price is considering delivery address in: **51 First Street, East Providence, Rhode Island 02914**	1	$ [redacted]
1A.FES	Price Adder for a field engineer supervision for field installation. Refer to section 5.2 for more details.	1	$ [redacted]

PPL
RI Energy Nasonville Transformer

07/07/23

2. SOLUTION DESCRIPTIONS AND PRICING

Item	Description	Qty.	Unit Price (USD)
1B	Three phase, oil immersed transformer, **33/44/55 MVA, ONAN/ONAF/ONAF**, 60 Hz, 65°C temperature rise, high voltage of **115 kV Delta** connection with No Load Tap Changer and low voltage of **13.8 kV Wye** connection with Load Tap Changer. - We are quoting these transformers EX Works (Incoterms 2010) Factory in Apodaca, N.L. México. Refer to section 5.4. - Dry air shipment	1	$[redacted]
1B.T	Unit price adder for transportation from **Factory** to deliver this transformer CIF (Incoterms 2010) at **NasonVille Substation - 445 Douglas Turnpike, Harrisville, Rhode Island, 02830.** Buyer shall provide, at its own expense, free and clear access to PGE and PGE's subcontractors for purposes of inspecting access routes to the delivery pad (if applicable). If such access is not allowed within thirty (30) days after execution or expedition of a binding Purchase Order, the quoted freight price shall be subject to applicable extra costs as necessary, according to PGE's subcontractor's inspections. Should PGE or its subcontractor deem it necessary to make modifications to access routes, or to use special equipment or maneuvers in order to perform proper delivery, Buyer shall make such modifications and/or bear the costs for any special equipment or maneuvers to be used. Upon arrival by GE Prolec or GE Prolec's subcontractors in charge of freight for delivery, the Purchaser shall promptly begin the applicable actions in order for proper delivery and reception to take place. If such actions are not started within 24 hours after arrival of the Products, the Purchaser shall hold GE Prolec harmless from and against any and all costs which GE Prolec might incur by reason of such delay, including but not limited to demurrage costs.	1	$[redacted]
1B.R	Unit Price adder for heavy hauling from the rail siding to the final destination and off-loading to the substation pad. Price is considering delivery address: **NasonVille Substation - 445 Douglas Turnpike, Harrisville, Rhode Island, 02830.**	1	$[redacted]
1B.FES	Price Adder for a field engineer supervision for field installation. Refer to section 5.2 for more details.	1	$[redacted]

Excel Attachment DIV 2-14-6

REDACTED

The Company provided the Confidential Excel file of Attachment DIV 2-14-6.

Division 2-15
Spare Transformers

Request:

Where will spare transformers be located? Are storage facilities or other site preparations required? If so, what are associated costs (by year) and has RIE included those cost estimates in the LRP?

Response:

The Company explored various spare transformer storage strategies such as storing them at a central warehouse managed by an RIE contractor or storing them at specific substations throughout the state. After review, the Company decided to strategically store them at various substations and company-owned facilities to reduce travel times, reduce the risk of losing all spares due to vandalism, limit the amount of make ready work, and gain efficiencies by combining spare transformer inspections with existing substation inspections.

There are several yards suitable for distribution spare storage:

1. Hopkins Hill Substation
2. Woonsocket Substation Distribution yard
3. Dexter Substation

The identified sites for transmission-specific spares are:

1. Sherman Road Substation
2. West Farnum Substation
3. Kent County Substation

Smaller replacement items that require indoor storage:

1. Providence Stock Room
2. North Kingstown Stock Room
3. North Kingstown Contracted Stock Room

All sites have been chosen based on the following parameters:

1. Site location allows trucking in/out with limited obstruction to oversized loads.
2. Security considerations.
3. Crane and rigging considerations related to requiring outages to load/unload spare equipment.
4. Projected future uses of the sites.
5. Availability of communications and power for monitoring of stored equipment.
6. Sites are out of the flood hazard areas.
7. Sites limit the amount of preparation work required to store equipment.
8. Accessibility for routine inspections to occur in tandem with scheduled inspections of current in-service equipment.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-15, page 2
Spare Transformers

Cost Considerations:

Costs were not included as part of this LRP. It is expected that engineering will begin in FY25 to include soil borings and studies required to develop a design and delivery strategy for all approved assets.

Construction for all to occur in FY2027 & FY2028.

The Company estimates:

- $50,000 per required foundation
- $10,000 per Oil Containment
- $2,000 for ac power and alarms
- Depending on the site, approximately $20,000 - $30,000 for fence installations.

These estimates will be reviewed and updated once all engineering and design has been completed for the foundation and fence installations.

The foundations will be installed in bulk for savings.

Projected Budget

FY2027	**FY2028**
18 Installs	3 Installs
$1,171,000	$221,000

Division 2-16
Spare Transformers

Request:

What is the assumed equipment failure rate (per year) used by RIE in the model and how was the rate determined?

Response:

The Company selected .5% for the assumed failure rate (per year). This number was chosen based on past practice at National Grid, historical failure rates at LG&E and KU, and PPL EU, along with using results from a Doble Engineering working group that surveyed 40 utilities over the past 7 years.

Division 2-17 - Corrected
Spare Transformers

Request:

How does the system reliability benchmark change as the number of spare transformers are reduced? Provide each resulting system reliability benchmark assuming decreasing transformer spares from 30 to 7 (e.g. what is the reliability benchmark for 30 spares, 29 spares, 28 spares, and so forth).

Response:

The referenced reliability criteria of 0.9950 does not refer to a system reliability benchmark but to the probability that a spare transformer will be available in the event of a failure. This reliability criteria is not directly linked to the system reliability benchmark.

The 23 additional spares address necessary spares for twenty-five category groups. Twenty-one of the groups require one spare transformer. Two groups require 2 spares. Two groups require 3 spares.

Reduction in the number of spares affects the reliability for that specific group. There is not an all-inclusive reliability number. Attached is the table that addresses the effect of the number of spares on the reliability criteria.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-17 - Corrected, page 2

Spare Transformers

Voltage and Rating	Winding Configuration	N # OF UNITS IN SERVICE	0	1	2
115-13.2kV 33/44/55 LTC	Delta-Wye	20	0.7408	0.9631	0.9964
115-13.2 24/32/40 LTC	Delta-Wye	34	0.6005	0.9067	0.9848
115-34.5kV 48/64/80	Delta-Wye	1	0.9851	0.9999	1.0000
115-34.5kV 33/44/55	Wye-Wye	7	0.9003	0.9949	0.9998
115-34.5kV 33/44/55	Delta-Wye	1	0.9851	0.9999	1.0000
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta	3	0.9560	0.9990	1.0000
115-34.5-13.8 24/32/40 MVA	Wye-Wye	2	0.9704	0.9996	1.0000
115-23kV 30/40/50	Delta-ZigZag	2	0.9704	0.9996	1.0000
115-23kV 30/40/50	Wye-Wye	6	0.9139	0.9962	0.9999
115-23-13.2kV 40/53/66	Wye-Wye-Delta	3	0.9560	0.9990	1.0000
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	2	0.9704	0.9996	1.0000
115-11.5kV 33/44/55MVA LTC	Wye-Wye	6	0.9139	0.9962	0.9999
69-13.8kV 24/32/40 LTC	Delta-Wye	1	0.9851	0.9999	1.0000
69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta	1	0.9851	0.9999	1.0000
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	5	0.9277	0.9973	0.9999
33.6-12.470Y kV 12/16/20 MVA LTC	Delta-Wye	6	0.9139	0.9962	0.9999
34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye	27	0.6670	0.9371	0.9918
34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag	1	0.9851	0.9999	1.0000
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	3	0.9560	0.9990	1.0000
34.5-4kV 6/7.5MVA LTC	Delta-Delta	1	0.9851	0.9999	1.0000
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye	4	0.9418	0.9983	1.0000
23-11.5 kV 7.5/9.375 MVA LTC	Delta-Delta	2	0.9704	0.9996	1.0000
23-11.5kV 10/12.5MVA	ZigZag-Delta	2	0.9704	0.9996	1.0000
22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye	14	0.8106	0.9808	0.9987
11.5-4.16/2.4Y kV 10.0/12.5 MVA LTC	Delta-Wye	2	0.9704	0.9996	1.0000

For example:

For the top listed category (115 – 13.2 kV, 33/44/55 LTC)

To achieve a reliability criteria of 0.9950, 2 spares are necessary. If only one spare is available, the criteria slips to 0.9631. If no spares are available, the criteria slips to 0.7408.

Corrected Response:

The Company is updating the table previously provided in this response because column 3 was inadvertently cut off. Please see the updated table below.

Division 2-17 - Corrected, page 3

Spare Transformers

		N				
Voltage and Rating	Winding Configuration	# OF UNITS IN SERVICE	0	1	2	3
115-13.2kV 33/44/55 LTC	Delta-Wye	20	0.7408	0.9631	0.9964	0.9997
115-13.2 24/32/40 LTC	Delta-Wye	32	0.6188	0.9158	0.9871	0.9985
115-13.2 12/16/20 LTC	Delta-Wye	2	0.9704	0.9996	1.0000	1.0000
115-34.5kV 48/64/80	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000
115-34.5kV 33/44/55	Wye-Wye	7	0.9003	0.9949	0.9998	1.0000
115-34.5kV 33/44/55	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta	3	0.9560	0.9990	1.0000	1.0000
115-34.5-13.8 24/32/40 MVA	Wye-Wye	2	0.9704	0.9996	1.0000	1.0000
115-23kV 30/40/50	Delta-ZigZag	2	0.9704	0.9996	1.0000	1.0000
115-23kV 30/40/50	Wye-Wye	6	0.9139	0.9962	0.9999	1.0000
115-23-13.2kV 40/53/66	Wye-Wye-Delta	3	0.9560	0.9990	1.0000	1.0000
115-11.5kV 33/44/55MVA LTC	Wye-Wye	6	0.9139	0.9962	0.9999	1.0000
69-13.8kV 24/32/40 LTC	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000
69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta	1	0.9851	0.9999	1.0000	1.0000
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	5	0.9277	0.9973	0.9999	1.0000
33.6-12.470Y kV 12/16/20 MVA LTC	Delta-Wye	6	0.9139	0.9962	0.9999	1.0000
34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye	27	0.6670	0.9371	0.9918	0.9992
34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag	1	0.9851	0.9999	1.0000	1.0000
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	3	0.9560	0.9990	1.0000	1.0000
34.5-4kV 6/7.5MVA LTC	Delta-Delta	1	0.9851	0.9999	1.0000	1.0000
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye	4	0.9418	0.9983	1.0000	1.0000
23-11.5 kV 7.5/9.375 MVA LTC	Delta-Delta	2	0.9704	0.9996	1.0000	1.0000
23-11.5kV 10/12.5MVA	ZigZag-Delta	2	0.9704	0.9996	1.0000	1.0000
22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye	14	0.8106	0.9808	0.9987	0.9999
11.5-4.16/2.4Y kV 10.0/12.5 MVA LTC	Delta-Wye	2	0.9704	0.9996	1.0000	1.0000

Division 2-17
Spare Transformers

Request:

How does the system reliability benchmark change as the number of spare transformers are reduced? Provide each resulting system reliability benchmark assuming decreasing transformer spares from 30 to 7 (e.g. what is the reliability benchmark for 30 spares, 29 spares, 28 spares, and so forth).

Response:

The referenced reliability criteria of 0.9950 does not refer to a system reliability benchmark but to the probability that a spare transformer will be available in the event of a failure. This reliability criteria is not directly linked to the system reliability benchmark.

The 23 additional spares address necessary spares for twenty-five category groups. Twenty-one of the groups require one spare transformer. Two groups require 2 spares. Two groups require 3 spares.

Reduction in the number of spares affects the reliability for that specific group. There is not an all-inclusive reliability number. Attached is the table that addresses the effect of the number of spares on the reliability criteria.

Division 2-17, page 2

Spare Transformers

Voltage and Rating	Winding Configuration	N # OF UNITS IN SERVICE	0	1	2
115-13.2kV 33/44/55 LTC	Delta-Wye	20	0.7408	0.9631	0.9964
115-13.2 24/32/40 LTC	Delta-Wye	34	0.6005	0.9067	0.9848
115-34.5kV 48/64/80	Delta-Wye	1	0.9851	0.9999	1.0000
115-34.5kV 33/44/55	Wye-Wye	7	0.9003	0.9949	0.9998
115-34.5kV 33/44/55	Delta-Wye	1	0.9851	0.9999	1.0000
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta	3	0.9560	0.9990	1.0000
115-34.5-13.8 24/32/40 MVA	Wye-Wye	2	0.9704	0.9996	1.0000
115-23kV 30/40/50	Delta-ZigZag	2	0.9704	0.9996	1.0000
115-23kV 30/40/50	Wye-Wye	6	0.9139	0.9962	0.9999
115-23-13.2kV 40/53/66	Wye-Wye-Delta	3	0.9560	0.9990	1.0000
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	2	0.9704	0.9996	1.0000
115-11.5kV 33/44/55MVA LTC	Wye-Wye	6	0.9139	0.9962	0.9999
69-13.8kV 24/32/40 LTC	Delta-Wye	1	0.9851	0.9999	1.0000
69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta	1	0.9851	0.9999	1.0000
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	5	0.9277	0.9973	0.9999
33.6-12.470Y kV 12/16/20 MVA LTC	Delta-Wye	6	0.9139	0.9962	0.9999
34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye	27	0.6670	0.9371	0.9918
34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag	1	0.9851	0.9999	1.0000
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	3	0.9560	0.9990	1.0000
34.5-4kV 6/7.5MVA LTC	Delta-Delta	1	0.9851	0.9999	1.0000
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye	4	0.9418	0.9983	1.0000
23-11.5 kV 7.5/9.375 MVA LTC	Delta-Delta	2	0.9704	0.9996	1.0000
23-11.5kV 10/12.5MVA	ZigZag-Delta	2	0.9704	0.9996	1.0000
22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye	14	0.8106	0.9808	0.9987
11.5-4.16/2.4Y kV 10.0/12.5 MVA LTC	Delta-Wye	2	0.9704	0.9996	1.0000

For example:

For the top listed category (115 – 13.2 kV, 33/44/55 LTC)

To achieve a reliability criteria of 0.9950, 2 spares are necessary. If only one spare is available, the criteria slips to 0.9631. If no spares are available, the criteria slips to 0.7408.

Division 2-18
Spare Transformers

Request:

What was the average age of power transformers on the system in 2015 (before South St. commenced), and what will be the average age of transformers on the system assuming the proposed LRP (long range plan) projects are implemented through the 2029 ISR Plan period?

Response:

The average age of distribution power transformers on the system in 2015 was 38.5 years.

The average age of distribution power transformers on the system in 2029 is projected to be 36.6 years.

Division 2-19, page 1
Spare Transformers

Request:

For the following statement: "There are approximately ten (10) substations where if a transformer fails, there isn't enough capacity on the remaining station transformer or feeder ties to restore all customers." (page 112)

a. Provide a list of the 10 stations and associated transformers that do not have N-1 contingency capability.

b. Provide a list of all substations and associated transformers that do have N-1 contingency capability.

c. Provide all updated CYME models used for the FY 2025 ISR Plan and all assumptions to demonstrate that there isn't enough capacity to serve load under a contingency for 10 substations. Include the estimated time frames (hours) that load would not be served. Identify any CYME models that have not been updated.

d. For each substation without enough capacity if a transformer fails, how was the lack of capacity addressed in each related Area Study? For any Area Study that did not address load at risk, provide the Company's rationale for not resolving the N-1 contingency through an Area Study solution.

Response:

Please see the responses on the subsequent pages.

Division 2-19, page 2
Spare Transformers

a. The 10 stations without N-1 contingency capability were an approximation. Please see the table below for the 15 stations and associated transformers that do not have N-1 contingency capability during peak loading. As a note, there are additional substations and transformers that do not have N-1 contingency capability; however, those transformers have an existing spare or mobile that can be used to restore customers.

Station	Transformer(s)
Washington	T261 & T262
New London	T2
West Cranston	T2
Wampanoag	T1 & T2
Staples	T124
Valley	T22 & T23
Dexter	T364
Tower Hill	T1
Chase Hill	T2
Newport	T1
Tiverton	T2
Shun Pike	T1
Johnston	T3
Elmwood	T2
Barrington	T1

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Division 2-19, page 3
Spare Transformers

b. Please see the table below for the stations and transformers that do have N-1 contingency capability where the load can be served via feeder ties from adjacent stations.

Station	Transformer(s)
Kenyon	T1 & T2
Westerly	T2 & T4
Wood River	T10 & T20
Bonnet	T2
Davisville	T1 & T2A
Lafayette	T1 & T2
Old Baptist Rd	T1 & T2
Peacedale	T1 & T2
Wakefield	T5
West Kingston	T1
Quonsett	T1 & T2
Admiral St	T1, T2, T3, T4 & T5
Franklin Sq	T3320, T3324, T2207, T2210, T2220 & T2260
South St	T2201, T2216, T2248 & T24
Clarkson St	T1 & T2
Lippitt Hill	T1 & T2
Point St	T1 & T2
Dyer St	T1 & T2
East George St	T1 & T2
Geneva	T1 & T2
Harris Ave	T1 & T2
Knightsville	T1 & T2
Olneyville	T1
Rochambeau Ave	T1 & T2
Sprague St	T1 & T2
Johnston	T1 & T2
Farnum Pike	T1, T2 & T4
Putnam Pike	T1 & T2
West Cranston	T1
West Greenville	T3
Clarke St	T651
Gate 2	T381
Harrison	T321
Hospital	T461 & T462
Jepson	T1, T3, T4, T5 & T6
Kingston	T312
Merton	T511

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Division 2-19, page 4
Spare Transformers

DIV-2-19b continued.

Station	Transformer(s)
West Howard	T541 & T542
Eldred	T2
Bristol	T1 & T2
Phillipsdale	T1 & T2
Warren	T1, T2, T5 & T6
Waterman Ave	T1 & T2
Kent Corners	T1 & T2
Anthony	T1 & T2
Division St	T1 & T2
Hope	T1 & T2
Hopkins Hill	T1 & T2
Kent County	T1, T2, T5, T6 & T7
Natick	T1 & T2
Warwick Mall	T1 & T2
Apponaug	T3 & T4
Kilvert St	T1 & T2
Lincoln Ave	T1 & T2
Pontiac	T1 & T2
Auburn	T1 & T2
Lakewood	T1 & T2
Drumrock	T3, T4 & T5
Sockanosset	T1 & T2
Valley	T21
Crossman St	T111
Pawtucket #2	T1 & T2
Dunnell Park	T1 & T2
Highland Park	T1 & T2
Riverside	T81 & T82
Woonsocket	T1
Tiverton	T1

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Division 2-19, page 5
Spare Transformers

c. CYME models are not needed for this type of analysis. The distribution planning department performs annual transformer contingency reviews based on peak loads seen throughout the year. These annual plans were used to develop this list. For this annual planning analysis, it is assumed that all customers can be restored within 24 hours. However, that assumption is based on the company having a spare transformer or mobile substation to serve the load. Without these being available, the company will need to rely on the existing mobile lease agreement or spare transformer purchase agreement with National Grid, or roll-on generation. There are many variables that determine how quickly the Company can receive equipment from National Grid. It is assumed that mobile equipment can be delivered and energized within 3-5 days while a spare transformer can take 1-2 weeks. The time to energize customers from roll-on generation will vary depending on the amount of unserved load, how long it takes contractor to transport the generation, and the location needing to be energized. In the past, this has taken anywhere from 1-4 days.

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Division 2-19, page 6

Spare Transformers

d. Please see the table below identifying if the transformer contingency concern was identified in the specific area study and how the Company plans on mitigating the concern. A transformer contingency concern would only be identified within a study if the unserved load over 24 hours was above 240MWHrs. However, this criterion assumed that the company had spare transformers or mobile substations that could be used to energize the remaining customers within 24 hours. The analysis to evaluate spare and mobile transformer needs should not be compared to load-at-risk contingency analysis.

Station	Area Study & Completion Date	Transformer Contingency Identified	Solution
Washington	Blackstone Valley South - 2022	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
New London	Central RI West – 2022	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
W. Cranston	North Central RI - TBD	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
Wampanoag	East Bay – 2015	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
Staples	Blackstone Valley South - 2022	No	The transformer contingency concern was identified during an earlier analysis effort and not identified in the 2022 area study. The installation of the Highland Park Substation reduced the load-at-risk from approximately 600 MWhrs to 270 MWhrs. Distribution Planning will be evaluating the remaining contingency load at risk and recommending a solution.
Valley	Blackstone Valley South - 2022	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
Dexter	Newport – 2022	Yes	The transformer contingency was identified during the study and will require additional analysis before a solution can be presented.
Tower Hill	South County East – 2018	Yes	The area study recommended a combination of new feeder ties to alleviate the load-at-risk. There will still be unserved load with these feeder ties.
Chase Hill	South County West - 2022	Yes	The area study identified the transformer contingency concern and proposed a second transformer at the station to mitigate the load-at-risk.
Newport	Newport – 2022	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.

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Spare Transformers

DIV-2-19d continued.

Station	Area Study & Completion Date	Transformer Contingency Identified	Solution
Tiverton	Tiverton – 2022	No	The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr.
Shun Pike	North Central RI - TBD	No	A more detailed North Central RI Area Study will be kicked off soon to evaluate this area. This substation only feeds one customer who is currently inactive.[1]
Johnston	North Central RI - TBD	No	A more detailed North Central RI Area Study will be kicked off soon to evaluate this area.
Elmwood	Providence – 2017	No	The study recommendations would retire this station. [2]
Barrington	East Bay - 2015	No	The study recommendations would retire this station. [3]

[1] This station is included for completeness. It does not impact the number of recommended spare transformers.
[2] This station is included for completeness. It does not impact the number of recommended spare transformers.
[3] This station is included for completeness. It does not impact the number of recommended spare transformers.

Division 2-20
Spare Transformers

Request:

The Company proposes purchasing a spare to back up two (2) in-service transformers that supply power to a local hospital.

a. Are the referenced transformers located in the Hospital #146 substation, or other location?

b. What are the ages, condition, capacity rating and peak loads of each in-service transformer?

c. What is the reliability exposure to the hospital in event of a transformer failure? Does the hospital utilize back-up generation?

d. Is the hospital substation identified for upgrades or expansion under an Area Study? If so, when is work planned? For any planned transformer replacements, provide the proposed capacity rating(s).

e. Under National Grid ownership, did RIE have access to a spare to back up the hospital? Regarding the alternative of establishing a spare transformer agreement with a neighboring utility

Response:

a. The referenced transformers are located at Franklin Square Substation (3320 and 3324 transformers).

b. 3320 Transformer
Waukesha serial #: A5168T
12/16/20 MVA
34.5 kV – 11 kV
Manuf. in 2004

3324 Transformer
Waukesha serial #: A5169T
12/16/20 MVA
34.5 kV – 11 kV
Manuf. in 2004

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Division 2-20, page 2
Spare Transformers

Both transformers are in good condition. The maximum load on each unit in 2023 was approximately 5 MVA (10MVA total).

c. The loss of either the 3324 or the 3320 transformer will drop the alternate feed to the RI Hospital resulting in the hospital being single sourced. Upon loss of the other transformer or associated line, or Franklin Square 11 kV bus, the hospital will revert to emergency generation. The hospital does utilize back-up generation. As part of the Company planning criteria, customer owned generation is not considered for loading or contingency planning.

d. The reference to Hospital Substation # 146 (Newport, RI) is not applicable to this request.

e. National Grid did not have a spare for these transformers. The transformer is atypical. It is an 11 kV delta to 34.5 kV zig zag transformer. The Providence area 11 kV distribution voltage is a "vintage" voltage that was optimum for 1920's electrical distribution construction technology. It is extremely unlikely that any neighboring utility would have an equivalent transformer in service and even less likely that they would have a spare. The proposed spare would also serve as a spare for the third equivalent transformer at Franklin Square which supplies the Fields Point natural gas liquefaction plant.

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Division 2-21
Spare Transformers

Request:

Regarding the alternative of establishing a spare transformer agreement with a neighboring utility;

a. How many spare transformers would RIE have access to under a regional lease or sharing agreement as compared to the proposed 30 spares in the LRP?

b. How many spares would RIE require on its system if a lease agreement were arranged, as compared to the proposed 30 spares in the LRP?

Response:

a. The Company has only reached out to one neighboring utility, National Grid, to discuss a spare transformer agreement. The existing spare transformer agreement with National Grid provides access to all spare transformers in Massachusetts. At the time of the sale, this figure totaled 54 spare transformers, which included 32 transmission assets, and 22 distribution assets. However, National Grid can deny a spare transformer request under certain conditions such as having a long-term disabling of one of their transformers, having a need for the transformer for an upcoming planned project, or if selling the spare transformer presents a reliability risk within the seller's electric system. National Grid also has the option of providing a mobile substation lease rather than offering to sell a spare transformer. If the Company does purchase a spare transformer from National Grid, then the Company will be responsible for paying for the replacement cost to buy a transformer of equal specifications or the Net Book Value of the spare transformer.

b. Due to the uncertainty of spare transformer availability as described in DIV-2-21a, the Company does not agree that a regional lease or sharing agreement is the most reliable strategy for spare transformers. The lease or sharing agreement is an effective strategy for catastrophic events where the planned spare inventory is depleted, but it should not be the primary spare transformer strategy. Therefore, the Company would require the quantity that is calculated using the provided spare transformer calculation spreadsheet.

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Division 2-22
Spare Transformers

Request:

The Company states that a lease agreement "is not a thorough long-term solution" and that "(n)eighboring utilities will want to establish a clause to pull back any leased equipment if a failure occurs on their system." (page 112)

a. If a neighboring utility pulls back leased equipment, would RIE load be unserved?

b. Would RIE have the right to pull back leased equipment under a lease agreement?

c. Would pulling back a spare transformer that is serving load be a low probability scenario and equitable distribution of risk to both parties?

Response:

a. There could be cases where there would be unserved load if a neighboring utility pulls back their leased equipment. The Company would look at other options to serve the customers in those situations such as installing roll-on generation via vendors already under contract.

b. The Company would have the right to pull back leased equipment.

c. The existing agreements between RIE and National Grid include a spare transformer purchase and sale agreement, and a mobile equipment lease agreement. National Grid can only pull back a mobile transformer through the lease agreement. While the agreement for the use of mobiles can be exercised by either company, the probability of National Grid using a RIE mobile is highly unlikely. This is due to the limited inventory owned by RIE that could be used by National Grid. The Company believes that it holds all the risk in the scenario of National Grid exercising its right to pull back mobile equipment which was purchased by its customers and is expected to be available to respond to situations in its service territory.

Division 2-23
Spare Transformers

Request:

If the need to maintain an adequate number of spare transformers is driven by transformer lead times approaching 3-years, and if the Company is not certain that 3-year lead times will continue in the future, why is RIE not considering lease agreements as lower cost, shorter term solutions until the supply chain disruptions settle? What type of arrangement governed spare transformer access across National Grid operating companies and how was that arrangement different from a leasing agreement?

Response:

PPL procurement does not predict significant reductions in the lead times of power transformers in the short term. This is driven in part by the predicted increase in needs that the nationwide shift to electrified heating and transportation will put on transformer manufacturers. Programs at the federal level are targeted at increasing adoption of these new technologies and will continue to drive the long lead times for station equipment. Looking to the future there will be less margin for transformers to remain out of service while replacement units are built further necessitating a robust spare and mobile transformer contingency plan.

RIE has considered leasing transformers from both transformer manufacturers and 3rd party vendors for several recent events. In all cases the units available were not suitable to fulfill the need. Leasing requires the lessor to have an appropriately sized and configured unit available. In addition, PPL and RIE are members of the EEI STEP Program.

National Grid had the ability to share spares and mobiles across (4) New England operating companies consisting of, The Narragansett Electric Company, The Massachusetts Electric Company, Nantucket Electric, and Granite State Electric prior to its sale to Liberty Utilities.

Due to the fact that the NY business already had a separate service company, there was limited sharing between NY and NE due to the inherent regulatory issues. National Grid did not use any transformer leasing models as part of their resiliency spare transformer program.

Division 2-24
Spare Transformers

Request:

What other transformer sharing opportunities has the Company explored both regionally and nationally? Has RIE had discussions with multiple regional utilities? Why or why not? Do all transformer lease agreements involve binding contracts?

Response:

RIE knows of two national transformer sharing programs, Edison Electric Institute STEP and North American Transmission Forum Restore. These programs involve the sharing of spare transmission transformers in the event of extreme events involving multiple transformer failures. These programs do not address substation distribution power transformers.

The only program that RIE is aware of for accessing substation distribution transformers from other utilities is the voluntary Edison Electric Institute SPAREConnect program. This program does not track or manage transformer inventories and there is no requirement for other utilities to help. This program provides access to points of contact at other utility companies so that participants can quickly get ahold of one another. Historically the sharing of substation power transformers between neighboring utilities has not been possible because of regulatory restrictions.

All the substation equipment lease agreements that RIE has made with National Grid have been legally binding contracts.

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Division 2-25
Spare Transformers

Request:

What non-wires alternatives has the Company considered, such as storage or customer sited solutions, to meet load at risk?

Response:

While the Company does consider non-wires alternatives for specific load-at-risk issues above planning guidelines, it does not consider non-wires alternatives when determining spare transformer requirements. Spare transformer requirements consider a number of load-at-risk locations, including cases below planning guidelines. It would be impractical and a much greater cost to install non-wires alternatives at all the load-at-risk locations. The Company is aware of mobile energy storage systems; however, these mobile batteries are typically too small to be practical. For instance a large tractor trailer size battery system may only be sized for 1 megawatt for 2 hours. A fleet of these mobile battery systems would be required to replace one spare transformer.

It is important to note that the load-at-risk contingency analysis considers spare transformers. For example, a transformer contingency issue may be quantified as 10 megawatts for 24 hours where 24 hours is the time to mobilize and install the spare transformer. This quantification with the spare assumption is used for sizing wires and non-wires contingency solutions. In other words, a non-wires alternative to address a contingency load-at-risk issue would still rely on spare equipment.

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Division 2-26
Mobile Substations

Request:

The Company states the following (page 114):

"The Rhode Island Energy distribution system is designed for N-1 contingency situations. As such, for a loss of a power transformer, load is expected to be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair/replacement of the failed transformer. Apart from transferring customers to an adjacent transformer or feeder ties, installing a mobile substation is the quickest solution to restoring customers and returning the system back to normal operating conditions."

The Company owns two mobile substations and proposes to purchase three additional mobile substations and one mobile regulator. The Company indicates that there are (10) substations where if a transformer fails, there isn't enough capacity on the remaining station transformer or feeder ties to restore all customers. (page 112)

a. If power can be restored to the majority of substations in event of a power transformer failure, why are additional mobile transformers needed on the system?

b. Does RIE have mobile substations to support any of the 10 substations without enough capacity? If so, identify the substations.

Response:

a. Mobile substations are utilized for a variety of purposes. The first, and most critical, is to return the system to pre-contingency conditions in the event of a transformer failure. Even though the majority of load can be returned to service within 24 hours by tying feeders together, this abnormal system configuration exposes a greater number of customers to outages and could result in low/high voltages throughout the feeder. By having a mobile substation, the Company is not only able to energize the customers from the original substation (eliminating the reliability risk), but the Company is also able to provide stable voltage.

Division 2-26, page 2

Mobile Substations

Mobile substations are also used to support capital projects. When specific construction activities occur at a substation and require one of the transformers to be out of service, the Company utilizes mobile substations to ensure the system remains reliable in the event of a failure. Transformer failures can occur at other substations while a mobile is being utilized for a capital project. Additional mobile substations will allow for a quicker installation at the failure location instead of having to de-energize and transport the mobile that is currently in-service.

The Company currently has 2 mobile substations in inventory. These mobiles only cover a fraction of the transformers that are currently in-service. Without additional mobile substations, the electric system will have greater exposure during emergencies and, in some cases, customers will be out of power until roll-on generation is installed, or the Company receives a mobile substation from National Grid.

b. RIE does not have a mobile substation to support the 10 substations without enough capacity.

Division 2-27
Mobile Substations

Request:

Provide a list of mobile substations owned by each National Grid affiliate (New York, Massachusetts, and Rhode Island) by voltage (high and low side) and capacity that were available to the Company under National Grid ownership (assume a date just before PPL acquisition). Identify mobile substations that are owned by RIE and located on the Company's system. Provide the same information for mobile substations available to the Company under PPL ownership indicating whether the mobile is owned by RIE or another entity. Identify mobile substations located on the Company's system.

Response:

Please see Attachment DIV-2-27-1 showing a list of mobile substations owned by National Grid NY & NE prior to the sale date. The highlighted mobiles (5616 & 7802) were owned by RIE.

Please see Attachment DIV-2-27-2 showing a list of RIE owned mobile substations located in Rhode Island

Please see Attachment DIV-2-27-3 showing a list of PA & KY owned mobile substations. These mobiles are located in either Pennsylvania or Kentucky.

NY	HV L-L (kV)		LV L-L (kV)		MVA	LTC	DETC	Mnf Date	Notes	Transport Dimensions		Jeep	Installed Dimensions		Battery	External Batteries	HV Interruption Device	LV Interruption
	Y	Δ	Y	Δ						Length	Width	Required	Length	Width	Voltage	Required		Device
1C		115	13.8/4.36	7.97/5.04/2.52	12	yes	yes	1997		576	96	no	576	tbd	n/a	no	fuse	breaker
OLD 2C		43.8/34.4	13.8/4.36	7.97/5.04/2.52	7	yes	yes	1963		394	96	no	394	tbd	n/a	no	fuse	breaker
NEW 2C	34.4	34.4	13.8/4.36	5.04/2.52	12	yes	no	2019	8.7MVA @ 2.52, HV LTC, Delta Tert	530	102	no	530	102	48	no	breaker	breaker
3C		113	34.5/23/13.8		7.5	yes	yes	2008	34.5&23 are 30° lead, 13.8 is 30° lag	576	102	no	576	232	n/a	no	fuse	none
4C		43.8/34.4/22.9	13.8/4.36	7.97/5.04/2.52	5	yes	yes	1970		380	96	no	380	178	n/a	no	fuse	recloser
7991		115	13.2		40	yes	no	2014	+/- 15% LTC	600	120	no	896	200	48	no	none; need switcher 7992	breaker
7C		115	13.8		28/34/36	yes	yes	1994		760, x w/jeep	102	yes	760	180	48	no	switcher	breaker
8C		115	13.2		40	yes	no	2017	+/- 15% LTC	683	120	no	683	200	48	no	switcher	breaker
9C	34.5	34.5/46	13.8/4.16	4.8/2.4	10	yes	yes	2011	4.16 is 30° lead	504	102	no	504	102	48	no	breaker	breaker
2E	110/67/33.5/23		13.8/4.36	5.04	5/4	yes	no	1963		540	96	no	540	tbd	n/a	no	fuse	breaker
3E		115	13.8		12/14	yes	no	2006	wye-wye is 60° lag	576	102	no	576	246	48	no	fuse	breaker
4E	67/34.4		22.9/13.8/4.36	5.04	12	yes	no	1978	wye-wye is 60° lag	486	95	no	486	198	48	no	switcher	none
5E		115	13.8		29	yes	yes	2003		750	96	yes	628	179	48	no	switcher	breaker
6E		34.4/22.9	13.2/4.36	5.04	12	yes	yes	2019		528	102	no	528	102	48	no	breaker	breaker
7E (7406)		115	13.2		40	yes	no	2009	+/- 15% LTC	600	120	no	896	180	125	yes	none; need switcher 7407	breaker
8E		69/34.5	13.2/4.4		15	yes	no	2013		586	120	no	586	154	125	yes	switcher	breaker
9E	34.5	34.5	13.2/4.4		12	yes	no	2016	wye-wye is 60° lag	492	102	no	492	102	48	no	breaker	breaker
3W		34.5		5.04	2/4	no*	yes	1953	*with regulators	294	96	no	294	96	n/a	no	fuse	recloser
4W		34.5		4.8	3/6	yes	no	2007		433	102	no	433	tbd	n/a	no	fuse	breaker
5W		115	13.8/4.36	5.04	9	no	yes	1964		444	96	no	471	323	n/a	no	fuse	recloser
6W		115	13.8		29	yes	yes	2004		750	96	yes	628	180	48	no	switcher	breaker
7W		34.4	13.8		7.5	yes	yes	1990		554	111	no	554	111	48	no	breaker	breakers
8W	34.5	34.5	13.8/4.16	4.8	7.5	yes	yes	1993		504	102	no	504	102	48	no	breaker	breaker
9W		115	46/34.5/23/11.5		40/46/50	no	yes	2008	Transformer Only	648	119	yes	648	170	250/125/48	yes	none	none
10W		115	4.36		12	yes	no	2020	+/- 15% LTC	552	96	no	552	198	48	no	switcher	breaker
11W		115	13.2		40	yes	no	2019	+/- 15% LTC	882 w/jeep	120	yes	722	200	48	no	switcher	breaker

NE	HV L-L (kV)		LV L-L (kV)		MVA	LTC	DETC	Mnf Date	Notes	Transport Dimensions		Jeep	Installed Dimensions		Battery	External Batteries	HV Interruption Device	LV Interruption
	Y	Δ	Y	Δ						Length	Width	Required	Length	Width	Voltage	Required		Device
4230	115/66.4	[redacted]	69/39.84	[redacted]	50	no	yes	1965(Rebuilt 2014)	Tertiary - 13.8 & 23 & 24 delta - 23& 24 wye for 33.3MVA	419	120	no	730	120	125	yes	separate switcher + 276 long and 170 wide when set up	none
7661	115/66.4	115	24/13.86 X 36/20.78	[redacted]	50	no	yes	1992(Rebuilt 2016)	Can Float X0 - LV has 180° switch phasing	607	102	no	919	175	125	yes	separate switcher + 276 long and 170 wide when set up	none
7408	[redacted]	115	13.2/7.62	[redacted]	40	yes	no	2009	+/- 15% LTC	600	120	no	912	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
8094	[redacted]	115	13.2/7.62	[redacted]	40	yes	no	2016	+/- 15% LTC, Has 3V0	600	120	no	912	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
7997	[redacted]	115	23/13.27 X 34.5/19/92	[redacted]	50	no	yes	2014	delta 30 degree wye ,Can Float X0, Has 3V0	576	108	no	888	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
7995	115/66.4	[redacted]	23/13.27 X 34.5/19/92	[redacted]	50	no	yes	2014	Can Float X0 - Can Float H0 - LV has 180° switch phasing, Has 3V0	576	120	no	888	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
7704	[redacted]	112	14.4/8.31 X 24/13.86	[redacted]	40	no	yes	1977(Rebuilt 2015)	No LTC - many times needs voltage regulator to meet bus voltage	557	96	no	879	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
7131B	[redacted]	115	13.8/7.97 X 4.16/2.4	[redacted]	25	yes	yes	1973(cotrols done 2014)	No LTC for 4.16kV - Moved on any available low profile trailer available	n/a	n/a	n/a	575 w/o trailer	135 & 170	125	yes	separate switcher + 276 long and 170 wide when set up	none
9879	[redacted]	69 X 34.5	13.2/7.62	[redacted]	30	yes	no	1995(Rebuilt 2017)	delta 30 degree wye, '+/- 15% LTC, X0 can Float	570	102	no	882	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
7802		34.5 X 22.9	13.2/7.62 X 4.4/2.54		12	yes	no	2013	delta 30 degree wye '+/- 15% LTC	480	102	no	480	102	125	yes	breaker	breaker
9890	24/13.86	24	13.2/7.62	[redacted]	31	yes	no	1995(Rebuilt 2017)	Does 30 degree phase shift or 0 degree '+/- 15% LTC - H0&X0 can float	480	102	no	480	102	125	yes	breaker	breaker
8001	[redacted]	22.9X13.2	13.2/7.62 X 4.4/2.54	[redacted]	8	yes	no	2015	+/-15% LTC on HV	396	102	no	396	102	48v - Has Battery System	no	recloser	breaker
5264	[redacted]	22.2X13.5	4.16/8.32	2.4/4.8	5	no	yes	1955									fuses	OCB
27805	22.9/13.2	[redacted]	13.2/7.62	[redacted]	15	yes	no	2019	0 degree phase shift'+/- 15% LTC, must be connected wye-wye.	513	102	no	513	102	48v- Has Battery	no	breaker	breaker
1754	66/38.1	66	23.4/13.5	13.5	8	no	yes	1952	0 degree phase shift'+/- 15% LTC, must be connected wye-wye.	411	124	no	411	124	none	no	fuses	none
5616	22.7/13.17	23 X 13.8	13.8/7.97 X 4.16/2.4	2.4	5	yes	yes	2020	. Many different vector configurations	413"	102"	no	413"	102"	can do AC or DC 125Volt	no	Nova recloser	RMAG breaker
6846	[redacted]	13.8	4.36/2.5	[redacted]	6.25	yes	yes	1968	Too many combinations to list - Rebuilt 2020 has original LTC	402	96	no	402	96	none	no	recloser	switch
8401	[redacted]	115	13.2/7.62	[redacted]	50	no	yes	2020	HV LTC - Can be installed outside sub fence. OH connections and lockable	636	108	no	948	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker
5179	[redacted]	69	13.2/7.62	[redacted]	40	yes	no	2021	Delta 180 zig-zag winding combination, Has 3V0, Has Rear Wheel Steering	636	102	no	948	175	125	yes	separate switcher + 276 long and 170 wide when set up	breaker

RIE	HV L-L (kV)		LV L-L (kV)		MVA	LTC	DETC	Mnf Date	Notes	Transport		Jeep Required	Installed Dimensions		Battery Voltage	External Batteries Required	HV Interruption Device	LV Interruption Device
	Y	Δ	Y	Δ						Length	Width		Length	Width				
7802		34.5 X 22.9	13.2/7.62 X 4.4/2.54		12	yes	no	2013	delta 30 degree wye '+/- 15% LTC	480	102	no	480	102	125	yes	breaker	breaker
5616	22.7/13.17	23 X 13.8	13.8/7.97 X 4.16/2.4	2.4	5	yes	yes	2020	. Many different vector configurations	413"	102"	no	413"	102"	can do AC or DC 125Volt	no	Nova recloser	RMAG breaker

[redacted]

KY	HV L-L (kV)		LV L-L (kV)		MVA	LTC	DETC	Mnf Date	Notes	Transport		Jeep Required	Installed Dimensions		Battery Voltage	External Batteries Required	HV Interruption Device	LV Interruption Device
	Y	Δ	Y	Δ						Length	Width		Length	Width				
E4723		34500 X 69000	34.5 x 4360 69 x 4360 34.5 X 13090 69 X 13090		15	NO	Yes	2016	Used in various sites in Kentucky									

Division 2-28
Mobile Substations

Request:

In the past ten years, how many times has the Company called upon a mobile substation from New York or Massachusetts to be utilized in Rhode Island?

Response:

The Company has called upon a mobile substation from New York or Massachusetts at least 10 times in the past 10 years to support capital projects or for emergency use.

Division 2-29
Mobile Substations

Request:

In the past ten years, how many times has a mobile substation owned by the Company been called upon to be utilized in New York or Massachusetts?

Response:

Using data provided to PPL prior to the sale, in the past ten years, a mobile owned by the Company has been used six times in New York or Massachusetts.

Division 2-30
Mobile Substations

Request:

Provide all workpapers and assumptions, in executable format, used to determine the need for three mobile substations and one mobile regulator.

Response:

Please see Attachments DIV-2-30-1 and DIV-2-30-2 showing the gap analysis and a workpaper justifying the 3 proposed mobile substations and 1 mobile regulator.

The gap analysis (Attachment DIV-2-30-1) shows the existing in-service transformers with a high voltage winding rated at 34kV or less. The stations with red font will be retired/replaced under existing projects and were not counted in the analysis. The load at risk sheets summarizes what existing mobile substation can be used to serve the load at risk. The red highlights show where a mobile cannot fully backup an existing in-service transformer because the ratings are above the mobile ratings. This means that the feeders will need to remain in an abnormal configuration until a new transformer is delivered. The sheet showing the load-at-risk for 115kV transformers is used to show the stations where we currently have unserved load. The Company does not have a mobile substation that is rated for 115kV. Therefore, these customers will remain without power until generation is installed or mobile equipment is leased from National Grid.

The Summary of Mobile Substation Needs document (Attachment DIV-2-30-2) is a workpaper that was used to summarize the justification for the mobile equipment.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Attachment DIV 2-30-1

The Company is providing the Excel version of Attachment DIV 2-30-1 (Public).
The confidential version of Attachment DIV 2-30-1 will be provided via a separate link.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

1.) Mobiles
    a. 3 Mobile Substations and 1 mobile regulator
        i. 115000Y/66400Vx115000V-23000Y/13270x34500Y/19920V, 50MVA, DY or YY mobile
            1. Justification:
                a. Twenty-three (23) 115-34 and 115-23kV transformers in the system
                b. Mobile can be installed within 3 days where a spare will take 10 or more days.
                c. Load at risk:
                    i. W. Kingston: T2 – 9.3MVA
                    ii. Wolf Hill: T1 – 12.2MVA (violates planning criteria)
        ii. 115000V-13200Y/7620V, 40MVA, LTC, DY
            1. Justification:
                a. Currently have fifty-two (52), 115-13.2kV transformers within the RIE territory
                b. No Spare transformers
                c. Mobile can be used temporarily for all capacity levels until a spare is delivered
                d. Eighteen (18) have a top rating of 55MVA
                e. Thirty-one (31) have a top rating of 40MVA
                f. Three (3) have a top rating of 20MVA
                g. Xfmr load at risk:
                    i. Nine (9) stations where we have load at risk if a transformer fails and no spare available.
                    ii. Washington: T261 – 3.5MVA, T262 – 5.7MVA
                    iii. New London: T2 – 3.3MVA
                    iv. W. Cranston: T2 - .8MVA
                    v. Wampanoag: T1 – 2.9MVA, T2 – 5.5MVA
                    vi. Staples: T124 – 10.4MVA (violates planning criteria)
                    vii. Valley: T22 – 4.0MVA
                    viii. Dexter: T364 -2.4MVA
                    ix. Tower Hill: T1 – 11.5MVA (violates planning criteria)
                    x. Chase Hill: T2 – 11.5MVA (violates planning criteria)
        iii. 34.5x23-12.47kV rated for at least 30MVA w/ LTC Mobile
            1. Justification:
                a. Currently have forty-three (43) 34/23-13.2/12.47kV transformers within the RIE territory
                b. Five (5) have a top rating greater than 25MVA
                c. Thirteen (13) have a top rating greater than 9.375MVA and less than 25MVA
                d. Twenty-five (25) have a rating of 9.375MVA or less
                e. Existing Spares:
                    i. Currently have two (2) spares with max rating of 9.375MVA

Division 2-31
Mobile Substations

Request:

Provide all workpapers and assumptions, in executable format, used to determine the proposed annual budgets for mobile substations/regulator totaling $16 million from FY 2025 through FY 2027.

Response:

Please see Attachment DIV 2-31-1 outlining the expected spend for the next three fiscal years.

Please see Attachments DIV 2-31-2 and DIV 2-31-3 for budgetary estimates for the three mobile substations and one mobile regulator. The estimate for the 30 MVA, 34.5x23-12.47 kV mobile substation was initially established by using historical knowledge and other estimates given at the time. This estimate was recently confirmed in Attachment DIV 2-31-3.

The assumed lead time for all equipment is three years with milestone payments of 10% upon purchase order, 30% upon engineering drawing review, 30% upon delivery, and 30% upon acceptance testing.

REDACTED

Equipment	Quantity	Cost		FY25	FY26	FY27
115000Y/66400Vx115000V-23000Y/13270x34500Y/19920V, 50MVA, DY or YY mobile substation	1	[redacted]		[redacted]	[redacted]	[redacted]
23/34 kV 50 MVA mobile regulator	1	[redacted]		[redacted]	[redacted]	[redacted]
115000V-13200Y/7620V, 40MVA, LTC, DY mobile substation	1	[redacted]		[redacted]	[redacted]	[redacted]
30 MVA, 34.5x23-12.47 kV, Mobile Transformer with an LTC	1	[redacted]		[redacted]	[redacted]	[redacted]
Total+$80,000 Freight	4	[redacted]	Total/FY	[redacted]	[redacted]	[redacted]

From: davidgenergycorp.com <david@genergycorp.com>
Sent: Wednesday, May 17, 2023 11:29 AM
To: Bleyer, John M <JMBleyer@RIEnergy.com>
Cc: Ben Abebe <babebe@deltastar.com>
Subject: Re: Cost Estimates for Mobiles For Planning Purposes: RI Energy

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

John,'

Rough estimate for Delta Starr MOBILES

The 50mva mobile might be too big depending upon features, losses, weight restrictions etc...

One (1), 115000Y/66400Vx115000V-23000Y/13270x34500Y/19920V, 50MVA, DY or YY mobile substation

[redacted]

One (1) 23/34 kV 50 MVA mobile regulator.

[redacted]

One (1), 115000V-13200Y/7620V, 40MVA, LTC, DY mobile substation

[redacted]

The above does not include freight or training

[redacted]

Lead time is currently running 110 to 120 weeks although order volume continues to be strong so that might inch out further

Thank you

David Shamlian
Genergy Corporation
2050 Western Ave Suite 201
Guilderland, NY 12084
518.424.1159 C
518.438.0822 O
David@Genergycorp.com

CORPORATE HEADQUARTERS
3550 Mayflower Drive
Lynchburg, Virginia 24501
(800) 368-3017

FACILITY & SERVICE LOCATIONS
Forest, Virginia
Saint-Jean-sur-Richelieu, Quebec
San Carlos, California

DELTA STAR

Eric J. Wiesner, PE
Rhode Island Energy
Email: EJWiesner@rienergy.com

November 9, 2023

Thank you for your interest in our mobile transformer solutions. Please see below our estimation for a budget price and scope:

Specification of the Transformer

- Unit 1: 30 MVA, 34.5x23-12.47 kV, Mobile Transformer with an LTC, LV Circuit Breaker & HV Circuit Switcher*

This budgetary price includes:

- Design
- Manufacturing
- Tests
- Preparation for transport

This budgetary price excludes:

- Field Service equipment training
- Installation & Commissioning
- Field work or Supervision
- Transportation

Incoterms: EXW—Lynchburg, Virginia USA

Current Lead Time: 100-110 weeks ARO from Lynchburg, Virginia; based on plant availability at time of order.

Budgetary Price NON-BINDING

- [redacted]
- *If substation equipment cannot fit on one trailer with the transformer, [redacted] The substation will be on two trailers.

Sincerely,
Jared Delello
(434)522-2411
Jdelello@Deltastar.com
Delta Star, Inc.

Division 2-32
Mobile Substations

Request:

Regarding Long Range Plan Alignment statement: "The mobile substation plan has taken into consideration the long-term plan by evaluating future transformer inventories and capital projects that will require a mobile substation to complete. This plan could change depending on the spare transformer inventory levels." (page 115)

a. Identify each Area Study project that will require a mobile substation to complete, describing why the mobile is required versus alternatives such as load transfers or construction schedule modifications to avoid a mobile requirement.
b. Were the mobile substation requirements identified when the Area Studies were completed, and were costs included in initial cost estimates?
c. Will mobile substations be installed concurrently to accommodate long range plan projects, or sequentially? If concurrently, can long range plan projects be sequenced in a manner to reduce the need for redundant mobile substations?

How is RIE going to change its proposed mobile substation procurements (planned by FY 2027) in reaction to long range plan projects (through FY 2034 and beyond) and spare inventory levels? Discuss in more detail how near term mobile substation purchase orders can be changed when long term conditions used to justify the purchases are uncertain.

Response:

a. Please see the Area Study projects below that will require a mobile substation to complete.

   Phillipsdale Substation 12.47 kV replacement. Backup of the 12.47 kV station at Phillipsdale is difficult. There are limited ties to Waterman Ave. Other area ties are not in phase with Phillipsdale. The substation yard is small, not allowing for construction while maintaining the existing 12.47 kV yard. Thus, a mobile or a temporary transformer will be required to supply the existing 12.47 kV load during construction.

   Hospital Substation Transformers and Switchgear Replacement. Since the existing switchgear encompasses all 4 kV feeds to Hospital and RIE distribution load, replacement of this equipment will likely require a mobile substation in order to maintain supply to the Newport Hospital. Detailed investigation into the construction sequencing and optimizing of new equipment may alleviate the need for a mobile.
   Knightsville Substation Rebuild. The substation is being rebuilt and converted to 15kV. The ongoing distribution line project is currently converting the existing 4kV

Mobile Substations

feeders to 15kV. To avoid overloading the adjacent 15kV feeders served from other area substations, the Company will be utilizing an RIE owned 5MVA mobile substation to serve the newly converted distribution lines. Once the station is built, the mobile will be removed.

Apponaug Substation Rebuild. This substation is being rebuilt on the same parcel of land. Depending on the final construction sequencing/outage plan typically defined in detailed engineering, the station construction might require a mobile substation during the relocation of one of the existing transformers to avoid overloading the 23kV supply to an adjacent substation.

Tiverton Substation 115kV Disconnect Switch Replacements. The two existing 115kV sacrificial switches will be replaced during this project. During replacement, the transformer associated with the switch will be unavailable. Due to the duration of the work, and the fact that Tiverton is an electrical island, a mobile substation will be used for reliability purposes.

Division Substation Transformer Replacements. Each transformer replacement will take between 1.5-2 months to complete. During this period, the station will be single sourced. A mobile substation will be required to ensure system reliability during each transformer replacement.

b. Mobile substation requirements are not included in Area Studies. The review of mobile substation requirements is addressed during the development of construction details and outage coordination.

c. Certainly, scheduling of construction projects can be dependent on mobile availability. If scheduling and mobile availability allow for and benefit from concurrent project construction, then the installations will be concurrent. If only one mobile is available, concurrent construction projects that require mobiles cannot be accomplished.

   It is not anticipated that changes to the long-range plan projects will change the proposed mobile substation procurements. If anticipated spare inventory levels are not realized, mobile substation requirements will need to be increased to provide adequate coverage.

   Justification of the purchase of mobile substations is primarily based upon coverage of the existing transformer fleet and not based on uncertain long-term conditions.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-33
Mobile Substations

Request:

If mobile transformers are temporary solutions in the event of a loss of a power transformer (page 114), and a lease agreement is adequate for a temporary solution to shore up the lack of mobile equipment (page 115), why does RIE dismiss a lease agreement as an alternative?

Response:

The Company does not believe that relying on a lease agreement with neighboring utilities is a long-term primary solution because the availability of mobile equipment isn't guaranteed. The neighboring utility can hold back mobile equipment if they have system needs and they can pull mobile equipment back if a failure occurs on their system while the mobile equipment is being leased. Capital projects also require mobile equipment depending on the scope of work. If the Company plans on leasing mobile equipment for a planned project, and the neighboring utility has a failure, the capital project schedule will be delayed, which could result in cost increases or asset failures. Due to these uncertainties, the Company does not believe the best contingency plan in response to a failure, or for capital projects, is to lease mobile equipment.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-34
Mobile Substations

Request:

Where will mobile substations be located? Are storage facilities or other site preparations required?

Response:

The Company explored various mobile substation storage strategies such as storing them at a central warehouse managed by an RIE contractor or storing them at specific substations throughout the state. After review, the Company will store mobile equipment at company-owned substation facilities to limit the amount of make ready work and time associated with routine readiness inspections. Site work such as oil containment and low voltage AC wiring will be needed for some of these locations.

There are several yards suitable for mobile substation storage. The list of acceptable sites is shown below:

1. Hopkins Hill Substation
2. Woonsocket Substation Distribution yard
3. Sherman Road Substation
4. West Farnum Substation
5. Kent County Substation
6. Dexter Substation

All sites have been chosen based on the following parameters:

1. Site location allows trucking in/out with limited obstruction to oversized loads.
2. Security considerations.
3. Availability of communications and power for monitoring of stored equipment.
4. Sites are out of the flood hazard areas.
5. Sites limit the amount of ready work required to store mobile equipment.
6. Accessibility for routine inspections to occur in tandem with scheduled inspections of current in-service equipment.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

Division 2-35

Mobile Substations

Request:

Why is another mobile substation required? Is the loss of the availability of the mobile fleet from National Grid and a lack of compatible mobile fleet from PPL at least one reason?

Response:

Additional mobile substations are required for multiple reasons such as logistical challenges with using mobiles stored in Pennsylvania and Kentucky, and the reduction in compatible mobile substations throughout the PPL operating system.

The primary role of a mobile substation is rapid response to an unexpected equipment failure within a substation. One of the most important planning decisions for a fast response is the storage location of the mobile substation. Except for the two mobile substations that RIE owns and stores in RI, the nearest mobiles are now located in Pennsylvania. The response time to use these mobile substations will be slower since oversized load permits are now required in more states. Some of the states aren't served by the PPL operating companies and their DOT has no incentive to expedite the required over the road permitting. The same would be true of rentals and leases from outside the Company.

RIE currently owns two mobile substations and stores them in Rhode Island. Both mobiles can only be used at substations that have sub-transmission or distribution voltages on the high and low side of the transformer. This only accounts for approximately 80 of the 200 transformers currently energized on the RIE electric system. With the loss of the National Grid mobile fleet, RIE does not have access to mobile equipment that can be used at substations that have voltages greater than 34kV or where the capacity requirements exceed 12MVA. These additional mobile substations will provide the equipment necessary to quickly respond to substation failures and to support upcoming substation capital projects. The mobile equipment that remained at National Grid was purchased by the ratepayers in Massachusetts. Therefore, even though RIE ratepayers had access to this equipment, they did not pay for this equipment and new mobile equipment should not be considered duplicative costs.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

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Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

December 1, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Division of Public Utilities and Carriers' Third Set of Data Requests in the above-referenced matter.

Please note that when responding to Division Set 3, the Company found a typographical error on Bates 146 of the FY 2025 ISR Plan. (The number was correctly stated on Bates 128). The following sentences on Bates 146 should read: "To account for additional recloser benefits, a separate analysis was conducted. A review of all events indicated approximately ~~60%~~ 80% of the total system frequency was associated with mainline issues which can be mitigated by the reclosers." The correction will be incorporated when the Company files the FY 2025 ISR Plan with the PUC.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

Division 3-1

Request:

Provide the Company's IEEE quartile results for SAIDI, SAIFI and CAIDI from 2012-2022. Provide for both regional utilities (describing the region) and nationally if available.

Response:

IEEE PES Distribution Reliability Benchmarking National Results are summarized as follows:

Natioal IEEE SAIFI Quartile											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Quartile	1st	1st	1st	2nd	2nd	1st	2nd	2nd	2nd	2nd	1st

National IEEE SAIDI Quartile											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st

National IEEE CAIDI Quartile											
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st

Northeast Investor-Owned Utility IEEE SAIFI Benchmarking Results are summarized as follows:

Regional IEEE SAIFI Quartile		
Year	2021	2022
Quartile	3rd	4th

Northeast Benchmarking Results prior to 2021 were not available currently.

Prepared by or under the supervision of: Ryan Constable

Division 3-2

Request:

Regarding the JD Power Electric Utility Residential Customer Satisfaction Study, RIE states that Q3 2023 Results indicate that the Company falls in the 3rd Quartile for overall satisfaction and specifically Power Quality and Reliability (FY 2025 ISR Plan, page 50). Last year, RIE stated that the 2022 JD Power study indicated that the Company fell in the 4th Quartile for overall satisfaction and specifically Power Quality and Reliability (FY 2024 ISR Plan, page 120). What does RIE attribute to the improvement over this time?

Response:

On page 50 of the Proposed FY25 ISR Plan, RIE benchmarked itself against similar regional utilities. Q3 2023 results indicated that the company falls in the 3rd quartile for overall satisfaction and specifically for Power Quality and Reliability.

On page 120 of the FY24 ISR Plan, the company stated JD power 2022 "Results indicate that the Company Falls in the 4th quartile for overall Satisfaction and specifically for Power Quality and Reliability."

RI Energy cannot speculate how specific customer responses may have changed from 2022 to 2023. However, the Company considers 3rd and 4th quartile performance to be poor.

Regardless of the specific ranking, RI Energy believes it is critical that the Company continue to invest in reliability programs to provide electric delivery service and improve customer satisfaction.

Division 3-3

Request:

Confirm that the JD Power Satisfaction Study examines six factors: Power Quality and Reliability, Price, Billing and Payment, Communications, Corporate Citizenship, and Customer Contact. Provide Rhode Island Energy's results for each factor and for overall satisfaction compared to other midsize eastern utilities, to the extent available, for each quarter of 2023, 2022 and 2021.

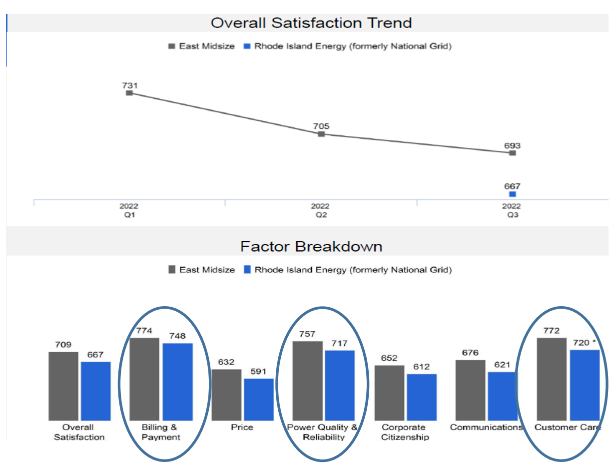
Response:

The J.D. Power's Residential Customer Satisfaction Study examines the following six factors: Power Quality and Reliability, Price, Billing and Payments, Communications, Corporate Citizenship, and Customer Care.

The Power Quality and Reliability section also notes additional factors within the category. They are: Provide Quality Power, Avoid Brief Interruptions, Avoid Lengthy Outages, Promptly Restore Power after an Outage, Keep (customers) Informed About Outages, and Supply Electricity during extreme temperatures.

Per our November 2022 response to Data Request DIV 3-6 of the Proposed FY 2024 Electric ISR Plan, the JD Power Electric Residential survey results are available for the Rhode Island Energy brand starting in Q3 2022. The RIE brand did not exist in the beginning of 2022.

The Q3 2022 results are shown below. Updated results will be forwarded when available. Please note that the dark gray bars represent the category mean with ½ of all respondents preforming above that target.



Prepared by or under the supervision of: Ryan Constable

Division 3-4
CEMI-4 Program

Request:

Is the Company using outage data based on the Rhode Island PUC definition of sustained interruption (loss of electric power lasting equal to or more than one minute) or the IEEE definition (loss of electric power lasting five or more minutes) to select CEMI-4 circuits? Will the Company measure and report results using the same methodology? If not the same, why?

Response:

The Company used outage data based on the Rhode Island PUC definition of sustained interruption to select CEMI-4 circuits for the program's first year because it matched the Company's legacy software. When reporting program results, outage statistics pre and post program will initially be consistent with the RI PUC definition of sustained interruption and noted within the results.

The Company does intend to transition the CEMI-4 program to an IEEE definition with a loss of power lasting five or more minutes as described in the response to FY 2024 Division 2-4. The Company anticipates that this transition will have a de minimis impact on CEMI circuit selection.

Division 3-5

CEMI-4 Program

Request:

How does RIE define Major Storms for purposes of the CEMI-4 program and is the definition consistent with the IEEE definition of Major Event Days?

Response:

Yes. RIE defines major storms consistent with the definition of an IEEE Major Event Day for the CEMI-4 program.

The Threshold Major Event Day (TMED) value is calculated at the end of each reporting year for use during the next year. Daily SAIDI for 5 sequential years are used to derive the threshold value.

The natural logarithm of each SAIDI value in the dataset is calculated.

The average of the logarithms (α) of the data set is calculated along with the standard deviation of the logarithm (β).

The major event day threshold, TMED, is calculated by using the equation:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

Any day that occurs during the subsequent reporting period with daily SAIDI greater than the threshold value TMED is designated a major event day.

Division 3-6
CEMI-4 Program

Request:

Is RIE's methodology to define both sustained interruptions and Major Storms consistent with the peer utilities reporting in the EEI survey (page 141, Table 3)?

Response:

RIE's methodology for defining sustained interruptions was not the same as that of peer utilities reporting in the EEI survey. EEI survey data was reported based on the standard IEEE 1366-2012 definition of a sustained outage. As noted in the response to Division 3-4, the RI PUC definition of a sustained outage differs from that of the IEEE. The RI PUC defines sustained interruptions as starting after 1 minute while the IEEEs defines them as beginning after 5 minutes. Currently, there is not a significant difference in CEMI performance based on the IEEE and RI PUC definitions.

RIE methodology for defining Major Event Days is consistent with the EEI survey results.

Division 3-7
CEMI-4 Program

Request:

Is RIE comparing CEMI-4 performance results to regional utilities that share similar attributes and that would experience similar weather patterns?

Response:

RIE does not have direct knowledge of other regional utility CEMI data. However, the Company reviewed the EEI survey used to benchmark the program to determine if regional results could be derived.

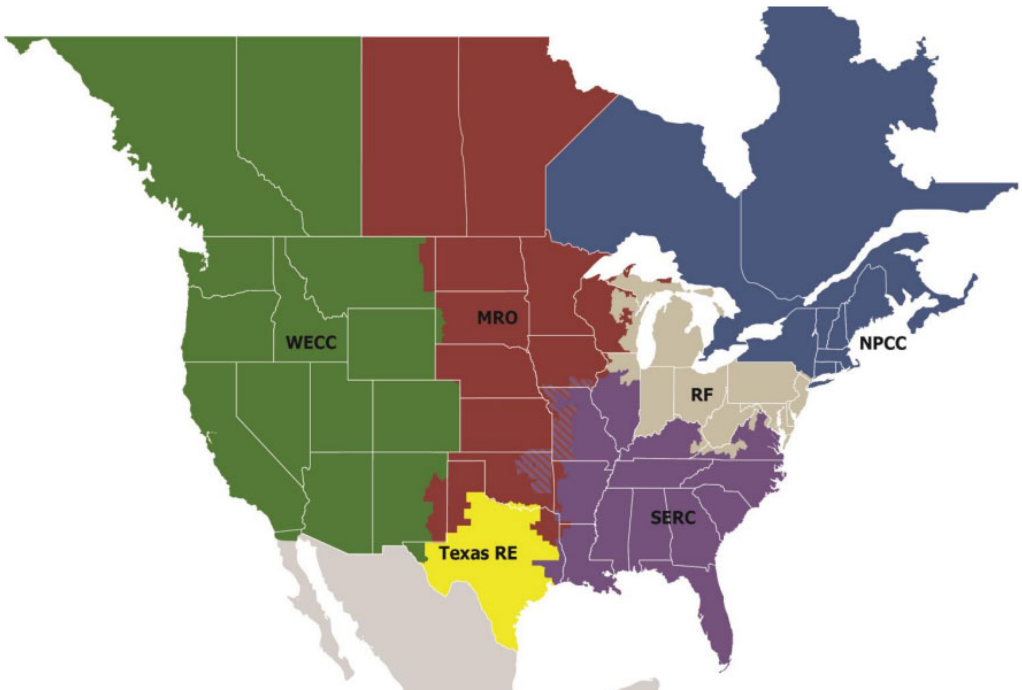
The 2020 Electric Edison Institute Reliability Survey collected data from 81 electric utility companies that serve approximately 80 million customers. The EEI Reliability survey is confidential. While the identity of each company is unknown, some participants voluntarily identified their governing Transmission Authority. From this, the Company can infer that approximately 50% of the companies came from the Northeast (NPCC), Mid Atlantic (RF), and Upper Midwest (MRO).

Weather patterns in these areas are closest to New England. See chart and region map below. However, only 57 survey participants reported CEMI results. The transmission region of the reporting companies is not known.

2020 EEI Survey Participants by Regional Transmission Entity			
Regional Entities	Name	Number of Participants	Percentage
NPCC	Northeast Power Corporation Council	11	13.6%
RF	Reliability First	27	33.3%
MRO	Midwest Reliability Organization	11	13.6%
SERC	Southeast Reliability Corporation	8	9.9%
TRE	Texas Reliability Entity	2	2.5%
WECC	Western Electric Coordinating Council	14	17.3%
Unknown	Region not voluntarily reported	8	9.9%

Division 3-7, page 2
CEMI-4 Program

North American Electric Reliability Corporation (NERC)
Regional Reliability Councils



Of those participants, 57 reported CEMI data.

Division 3-8
CEMI-4 Program

Request:

Why is RIE considering major storms in the CEMI-4 program? What other reliability programs does RIE implement that rely on data with major storms? Provide a copy of the Company's resiliency investment strategy, outlining how the CEMI-4 program aligns or complements this strategy.

Response:

RIE includes major storms in the CEMI–4 program because the customer experience is the same regardless of whether the interruption event will be excluded from regulatory reporting.

As shown in the chart below (and on pg. 141, Attachment 7, in Table 1 of the FY25 ISR proposed filing) an additional 259,974 customers are interrupted annually during regulatory excluded events. Failing to include these outages would miss 35% of all customers interruptions on the Company's system.

RI Energy SAIFI with and without Major Storms							
		Regulatory Reported SAIFI			SAIFI Including Major Storms		
Year	Customers Served	No. Of Events	Customers Interrupted	SAIFI	No. Of Events	Customers Interrupted	SAIFI
2019	496,961	2711	508,130	1.02	4587	689,698	1.38
2020	498,157	2721	471,406	0.95	5427	826,935	1.66
2021	499,886	2911	477,691	0.96	5008	720,516	1.44
Averages	**498,335**	**2781**	**485,742**	**0.98**	**5007**	**745,716**	**1.49**

While the Engineering Reliability Review (ERR) program is prioritized based on reliability data excluding major storms, the engineer will look at major storm data when analyzing the issues and developing solutions. Adding these events provides an opportunity to see where outages occur when the distribution system is under stress. Identifying these trouble areas is good utility practice.

The Company recognizes that, while the threat of climate change is significant, it is not an acute concern that can be resolved through isolated or short-term initiatives. Accordingly, preparing for and responding to climate change is embedded in the way the Company plans, constructs, and operates its system as a normal course of business. The Company has developed robust processes in each of the areas listed below which allow the Company the ability to respond both proactively and reactively as the impacts of climate change on distribution system reliability and resiliency performance, are realized.

CEMI-4 Program

1. The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure;

2. The Company's vegetation management programs;

3. Asset Management practices and the distribution system planning studies that are executed to identify existing and project future system performance concerns and the infrastructure development required to address the concerns identified;

4. The consideration of both reactive and proactive infrastructure development programs, such as CEMI-4, that adopt new, replace, and/or modify existing assets within the Company's infrastructure; and

5. The development, continued refinement, training, and execution of the Company's Emergency Response Plan.

Electric Power Research Institute (EPRI) and the North American Transmission Form defines[1] resiliency on all components of the electrical system:

The ability of the system and its components (both equipment and human) to ***1)*** *prepare for* ***2)*** *anticipate,* ***3)*** *absorb, and* ***4)*** *adapt to, and* ***5)*** *recover from non-routine disruptions including high impact low frequency (HILF) events in a reasonable amount of time. Where:*

1) ***Prepare*** *involves both longer-term mitigation strategies (e.g. system hardening),*
2) ***Anticipate*** *provides situational awareness before and during the event*
3) ***Absorb*** *requires inherent robustness of the system and supporting processes during the event.*
4) ***Adapt*** *entails flexibility and scalability of the system and supporting processes during and event*
5) ***Recovery*** *relates to response and recovery activities during an event.*

[1] From the EPRI North American Transmission Forum Understanding the Definition of Resilience (Companion Document) Document ID: 1644, approval date 11/03/2022. See https://www.natf.net/docs/natf/documents/resources/resiliency/understanding-the-definition-of-resilience-(companion-document).pdf

Division 3-8, page 3
CEMI-4 Program

Further, EPRI's three year (2013 to 2015) task force on Distribution Grid Resiliency highlighted six areas of research to address resiliency on the distribution network. They are: overhead structures, vegetation management, undergrounding, modern grid technology, and storm responses.

RIE considers the reliability work done under the FY 25 CEMI program, and all of its reliability programs, to directly contribute to overall system resiliency. For example, reconductoring open wire to tree resistant construction has preparation and absorption characteristics and advanced reclosers have anticipation, adaption, and recovery characteristics.

Prepared by or under the supervision of: Ryan Constable

Division 3-9
CEMI-4 Program

Request:

Why is RIE adopting a CEMI-4 threshold instead of a higher value, such as CEMI-5, at the outset of the program?

Response:

The program is designed for complete execution. At the outset of any program, the highest priority work is selected. While the program is designed to limit the percentage of customers experiencing four or more interruptions to 4.67 %, the immediate investigations and recommended solutions focus on customers well above that threshold, typically in the range between 6 and 10 interruptions. See Attachment 7, Table 5 for a list a of RIE circuits with higher CEMI totals.

Further, a quantitative assessment of the programs benefits was done using the U.S. Department of Energy's Interruption Cost Estimate (ICE) Calculator. The tool is designed to compare the costs of the reliability program against perceived benefits. See page 145, Attachment 7, section 4.3 Benefits for detail. All customers classes were assumed to be residential and reliability improvements were limited to three interruptions (from 4 to 1). The programs net benefit to cost ratio was calculated to be a positive 1.59. The positive benefit to cost ratio remains valid for reliability improvement of three interruptions regardless of the starting CEMI threshold. This is, CEMI investments that move the number of interruptions from 8 to 5 have the same positive benefit as investment as those that lower CEMI from 7 to 4.

Prepared by or under the supervision of: Ryan Constable

<u>Division 3-10</u>

CEMI-4 Program

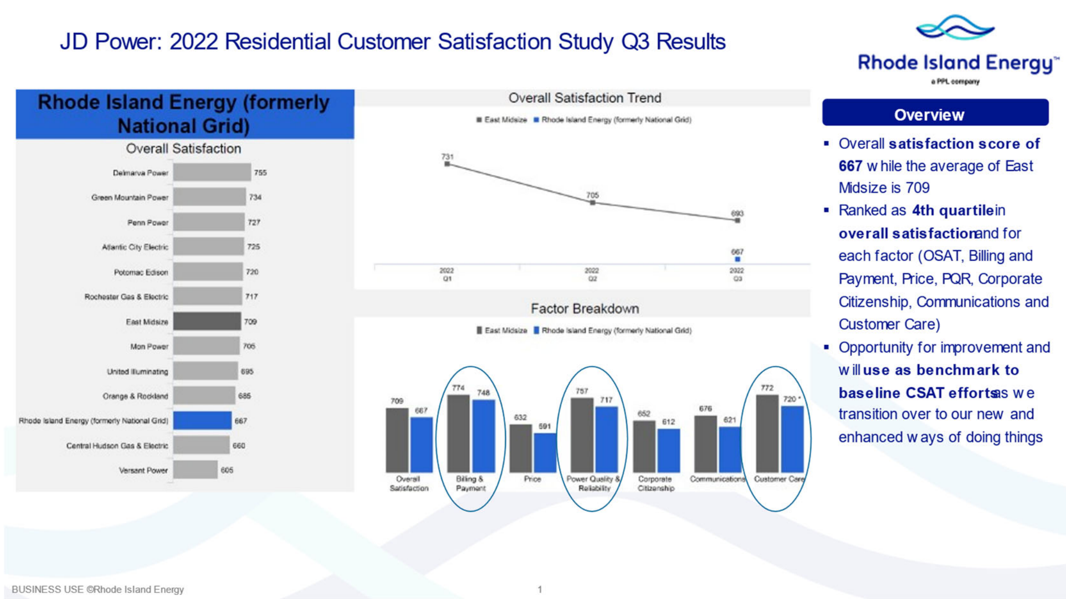
<u>Request</u>:

Why does RIE use the rationale that "JD Power 2022 3rd quarter results for RI Energy indicate residential customers overall satisfaction trended lower for the third consecutive quarter" (page 141, footnote 3) as support for the CEMI-4 program when the survey results are actually improving over the previous year?

<u>Response</u>:

The information used to create the foot note came from the JD Power 2022 Residential Customer Satisfaction Study Q3 results, summarized in the slide below. The Overall Satisfaction Trend (Center -top of side) indicates a Q1 score of 731, followed by a Q2 score of 705. Lastly, the third quarter score drops to 693 for a third consecutive quarter.

Q3 2022 was used because it was the first quarter in which survey results are specific to RI Energy. Before then, the Narragansett Electric results were rolled up into National Grid.



Prepared by or under the supervision of: Ryan Constable

Division 3-11
CEMI-4 Program

Request:

In the FY 2024 ISR Plan, the Company proposed $7.8 million over 5 years for the CEMI-4 program. In the FY 2025 ISR Plan, RIE proposes $20.6 million over 5 years for the same program. Why did the CEMI-4 program budget dramatically increase over the past year? If RIE could meet its internal goal to achieve first quartile performance results by expending $7.8 million over five years, why would the Company now propose a $20.6 million budget?

Response:

The budget increased for two reasons. The first reason was explained previously. For the FY 2024 ISR Plan, recloser costs were shifted out of the CEMI-4 program to avoid duplication and to better explain the overall recloser effort. As a result of collaborative discussions, these recloser amounts were shifted back to the CEMI-4 program to achieve the stated goals of the program. This results in an increase from the $7.8 million FY 2024 levels to approximately $12.3 million. The second increase is associated with reclosers shifted to the CEMI-4 program for overall circuit reliability improvements. This was done to avoid overlap with the Distribution Automation Recloser Program and increase work efficiency. Often circuits with high CEMI values can often have high circuit frequency and duration statistics. This is true for 100% of the FY25 CEMI circuits as can be seen in Attachment A to the Distribution Automation Recloser Program document. It would be inefficient to progress the same circuits under the two programs.

Division 3-12
CEMI-4 Program

Request:

On page 38, RIE states that the "CEMI-4 Program will identify and fix reliability issues for customers experiencing significantly poorer service than system or circuit averages with a goal of first quartile performance within five to ten years." The Company also states that the "goal of RI Energy's CEMI program is to bring CEMI 4+ performance to EEI first quartile levels within 5 years" (page 141).

a. Why does RIE consider first quartile CEMI-4 performance a necessary reliability goal?

b. How did RIE establish a timeline to achieve first quartile performance? Is the timeline five years, ten years, or other?

c. What are the risks to overall system performance if the timeline is extended?

d. Once first quartile performance is achieved, will the CEMI-4 program cease? Does RIE intend to maintain first quartile performance in future years and if so, what investments would be required?

Response:

a. RIE considers reliability to one of the paramount goals of the utility, along with safety and cost effectiveness/efficiency. First quartile CEMI-4 performance does not mean that all customers no longer experience 4 outages per year. Even with first quartile performance, approximately 4.6%, or 23,000, of the customers would still experience 4 outages per year. Recognizing that even first quartile performance leaves many customers with poor reliability, RIE considers first quartile performance a necessary goal.

b. RIE established the timeline to achieve first quartile performance based on reasonableness of execution. Although CEMI values are an important reliable statistic, this program is new to RIE. The timeline was developed to get to first quartile performance as soon as possible considering the typical circuit scope and the estimated number of circuits in the program per year.

c. As described in FY 2024 ISR Division 2-2, the Company explained the CEMI-4 program impact on overall system performance (SAIFI and SAIDI metrics) is trivial, as the CEMI metric is not a system based value and should not be compared to system based numbers. If the timeline is extended or not, the impact on overall system performance is trivial.

CEMI-4 Program

However, the risks of extending the CEMI program timeline can be compared against the CEMI goals. If the timeline is extended, the risks are the deferral of the reliability improvements and continued yearly high frequency of outages for the targeted subset of customers.

d. Once first quartile performance is achieved, the CEMI-4 program will continue but at a much reduced investment level to maintain performance. The Company is receptive to ending the formal program and incorporating a CEMI prioritization requirement into the Engineering Reliability Review (ERR) program. Because maintaining the program after achieving first quartile performance will result in ad-hoc analysis and work, RIE has not developed an investment plan.

Division 3-13
CEMI-4 Program

Request:

The Company indicates that using the experience of the average customer drives planning and investment decisions to parts of the system that have the highest customer densities and that "(t)his leads to uneven reliability performance across the distribution circuits and unhappy customers." (page 37)

a. Is it possible to achieve even reliability performance across the system for both blue-sky and storm conditions?

b. Is it practical to achieve even reliability performance across the system for both blue-sky and storm conditions?

c. Is uneven reliability performance across the distribution circuits an unsatisfactory outcome if the Company's overall system performance meets and exceed regulatory targets?

d. Provide a list of other utilities which do not have uneven reliability performance.

e. Does RIE agree that uneven reliability performance is inherent with electric utilities and the varying conditions in which power lines traverse? If not, explain why not.

f. Provide every reason RIE believes even reliability performance across the entire system is beneficial and provide the BCA which demonstrates the benefits outweigh the cost. Explain the rationale for an even reliability performance across the entire system.

g. Isn't it more likely than not that the first customer served on a circuit outside a substation will have better reliability than the last customer served on a circuit from a substation?

h. Is RIE proposing all customers on the circuit have the same reliability regardless of the circuit length, the type of area the circuit is traversing and regardless of the number of customers on the circuit or the type of customers on the circuit?

Response:

a. No, RIE believes it would be impractical to drive towards even reliability performance across the system for both blue-sky and storm conditions and the Company is not claiming this is an intended goal. The recognition of "uneven reliability performance" between the average customer as measured by system statistics and the subset of

Division 3-13, page 2
CEMI-4 Program

customers targeted by the CEMI-4 program is intended to demonstrate the importance and need of the CEMI-4 program. The intent of the program is to lessen the gap of reliability performance, but it is not to eliminate the gap entirely to even performance across all customers.

b. See the response to part a. above.

c. The Company believes that uneven reliability performance to the extent demonstrated by the CEMI-4 program analysis is an unsatisfactory outcome. The Company has explained that a CEMI-4 evaluation should not be compared to overall system performance whether it does not meet, meets, or exceeds regulatory targets.

d. All utilities have uneven reliability performance. Please see the response to part a. above. The following is a list of utilities and/or their regulatory agencies known to recognize that Customers Experiencing Multiple Interruption is an important metric highlighting uneven reliability performance:[1]

- Pacific Gas and Electric (California) – CEMI-5, 12
- Southern California Edison (California) – CEMI-12
- San Diego Power and Light (California) – CEMI-12
- Eversource (Connecticut) – CEMI-3, 5, 7, 9
- Florida Power and Light (Florida) – CEMI-5
- Duke Energy (Florida) – CEMI-5
- Gulf Power (Florida) – CEMI-5
- JEA (Florida) – CEMI-4, 5
- Baltimore Gas and Electric (Maryland) - CEMI-2, 4, 6, and 8
- Potomac Electric Power Company (Maryland, DC) - CEMI-2, 3, 4, 6, and 8
- Delmarva Power (Delaware, Maryland) - CEMI-2, 4, 6, and 8
- Potomac Edison Company (Maryland) - CEMI-2, 4, 6, and 8
- DTE Energy (Michigan) - CEMI-1 to 10
- Atlantic City Electric (New Jersey)
- Northern States Power (North Dakota) - CEMI-4 to 6
- Avista (Washington) - CEMI-0 to 6
- BC Hydro (British Columbia) - CEMI-4
- Vattenfall (Sweden) – CEMI-4, 12

[1] https://www.sandc.com/globalassets/sac-electric/documents/public---documents/sales-manual-library---external-view/technical-paper-100-t128.pdf?dt=637309315749384549

Division 3-13, page 3
CEMI-4 Program

e. Yes, RIE agrees that uneven reliability performance is inherent with electric utilities. RIE has not claimed otherwise. See the response to part a. above.

f. See the response to part a. above. RIE does not believe even reliability performance is practical and has never claimed such. Therefore, RIE cannot provide a BCA for a case which has never been presented by the Company.

g. Yes, it is more likely than not that the first customer served on a circuit outside a substation will have better reliability than the last customer served on a circuit from a substation. This is basic concept of distribution reliability. However, system reliability metrics will always favor the customers near the substation and may ignore the customers further from the substation with lesser reliability. A CEMI metric is intended to address this blind spot in system metrics and bring the reliability experience of more remote customers closer, but not equal to, the average customer.

h. No, RIE is not proposing all customers on the circuit have the same reliability regardless of the circuit length, the type of area the circuit is traversing and regardless of the number of customers on the circuit or the type of customers on the circuit. CEMI programs do not claim this as a goal. See the response to part a. and part g.

Division 3-14
CEMI-4 Program

Request:

The Company plans to spend over $25 million to address "uneven reliability performance across the distribution circuits and unhappy customers." (page 37) Is CEMI-4 a customer satisfaction program?

Response:

The CEMI-4 program is a reliability program as described in Sections 2 and 3 of the CEMI Program document. That said, when customers experience 4 or more outages in a year, this is often correlated with low customer satisfaction.

The view that reliability has a close relationship to customer satisfaction is substantiated by IEEE Std. 1782-2014 page 107, Section 6.5.3 **Customer/transformers experiencing multiple Interruptions (CEMI):**

"*Some companies have collected substantial information about the impact on customer satisfaction of repeated customer interruption events whether sustained, momentary, or during major events. The results show that there is a high correlation between customer dissatisfaction and a large number of repeated interruptions."*

Prepared by or under the supervision of: Ryan Constable

Division 3-15
CEMI-4 Program

Request:

How does the Company record complaints related to sustained interruptions? Are complaints recorded separately for blue-sky and storm conditions? How does the Company use the information to address areas of poor performance? Discuss or provide underlying information to indicate trending in customer outage complaints.

Response:

Customer complaints concerning sustained outages were handled on an ad hoc basis. Complaints filtered in from multiple sources (both internal and external to the Company) such as from the RI PUC, RI state representatives, municipal service representatives, field personnel, and direct calls from customers to engineering departments. Each sustained interruption complaint is addressed individually by the area Designer or Field Engineer.

Sustained interruption complaints are not recorded separately for blue-sky or storm conditions because the reporting status of the outage(s) are typically irrelevant to the customer.

The Company addresses poor performance by assigning the complaint to an RI Energy Field Engineer. The engineer will look up the customers' circuit information and then query the Interruption Disturbance Database (IDS) for the time of interest. Typical outage searches are from 1 to 5 years' depending on the nature of complaint. An outage report is queried from IDS to assist the Field Engineer with the investigation. Interruption records details include the type of protective device that operated, the location, the failed component and event comments recorded by the control room operator. A sample outage query for the 56-63F6 (Excel file) is included with this response as Attachment DIV 3-15. The outage locations are then reviewed on geospatial map, typically CYME or GIS software.

The investigating Engineer will look at the event causes at each of the circuit device locations to find repeat outages, event trends, frequent trouble spots, service equipment failures, and physical field conditions to determine solutions. Often the Field Engineer will engage with the area Operations Supervisor to get firsthand accounts of the circuit's performance.

Once the plan is developed. the actions are communicated back to the customer.

Attachment DIV 3-15

The Company provided an Excel version of Attachment DIV 3-15

Prepared by or under the supervision of: Ryan Constable

Division 3-16
CEMI-4 Program

Request:

In executable format, provide the following for the past five years:

a. Reliability data in Table 1 (page 141) using the Regulatory reporting methodology

b. Reliability data in Table 1 using the IEEE methodology

c. CEMI data in Table 2 (page 141) both with and without storms

d. EEI CEMI quartile results, storms included (Table 3, page 141), and without storms if available

Response:

Please see Attachment DIV 3-16 in response to this request.

Attachment DIV 3-16

The Company provided Attachment DIV 3-16 as an Excel file.

Prepared by or under the supervision of: Ryan Constable

Division 3-17
CEMI-4 Program

Request:

Provide the EEI annual Reliability Survey Report (referenced on page 140) for 2020, 2021 and 2022.

Response:

EEI's annual Reliability Survey Report is confidential. The publication is for internal use only of the Edison Electric Institute (EEI) participating member companies. It is not to be quoted, reproduced, or distributed without the advance, written permission of EEI, its member companies, its committees, and any person acting on behalf of any of them.

RI Energy has requested permission from an EEI representative. The Company will forward the reports if the appropriate permission is granted.

However, the Company notes that each year, EEI declines a number request from EEI members, non-EEI members, regulatory agencies, and academic institutions for copies of the report.

Division 3-18
CEMI-4 Program

Request:

On pp. 141-142, the Company describes the process to develop dataset lists of circuits with the highest CEMI n customers that are used to determine final circuit selections. Confirm that RIE will perform this assessment each year using the most recent reliability data. Will final circuit selection, proposed improvements, and cost estimates be completed prior to the initial proposed ISR Plan filing each year? If not, explain.

Response:

RI Energy's Distribution Planning and Asset Management group will compile two datasets to prioritize circuit selection. The first dataset, shown in Table 4, on page 142, Attachment 7, of the proposed FY 2025 ISR Plan, is a list of 3-year CEMI 4+ data on a rolling quarterly basis. The second data set lists the circuit's that have the highest CEMI numbers for the previous rolling 12 months. See Table 5 on page 143, Attachment 7, of the proposed FY 2025 ISR. The Company will perform circuit selections assessment with the most recent rolling quarterly and monthly datasets. Typically, both data sets end on the last day of June before the new fiscal year.

RI Energy has set a tentative schedule to begin data gathering in July. Circuit selections would be ready for the proposed ISR filings. However, a complete list of improvements, firm project scopes, and cost estimates will not be finished ahead of the ISR filing process. This is a common practice with programs where test data is used to setup program cash flows. Then the specific work is designed and executed to meet the system needs, which may not be aligned with regulatory timing. The actual costs for the specific work are reconciled at the appropriate time.

A benefit/cost analysis was completed for the program. This benefit/cost analysis will not be revised on a yearly basis.

Division 3-19
CEMI-4 Program

Request:

On page 142, the Company states that a weighted evaluation will be used that appropriately balances chronic CEMI 4+ performance and the highest current year CEMI n customers. Explain how this weighted evaluation is performed and provide examples. What determines appropriate balance?

Response:

RI Energy compiles two datasets to prioritize initial circuit selections. The first dataset, shown on page 142, Attachment 7, Table 4, of the Proposed FY25 ISR filing is a list of 3-year CEMI 4+ customer counts on a rolling quarterly basis. This shows the number of CEMI 4 + customers over a three year history. It is a good indication of circuits with chronically high CEMI 4 + customer counts. The second data set lists the circuits that have the highest CEMI(n) customers for the previous rolling 12 months. See page 143, Attachment 7, Table 5 for a sample. This addresses the acute concerns of customers who have recently experienced poor reliability.

The weighted evaluation is done by ranking circuits by three year CEMI 4 + averages in inverse order (the circuit with the highest customer count receives the lowest ranking) and listing the circuit's most recent rolling 12 month CEMI(n) in a table. See sample table below of the program's initial year. With CEMI (n) as the priority ranking, the appropriate balance is determined by selecting enough circuits with immediate poor customer experiences to meet the program's goal of addressing 9000 chronically impacted customers annually.

Once the candidate list is compiled, the final circuits are picked with input from RI Energy's Operations group. The Company will also consider proposed area study work and other pending capital projects to effectively align and balance work across all other capital and programmatic work streams.

RIE recognizes that there are more circuits selected under this criterion than the program funds annually. However, the number of candidate circuits with high CEMI (n) and Chronic CEMI 4 + customer should reduce as the program matures.

Division 3-19, page 2

CEMI-4 Program

CEMI Program Candidate Circuit Data 2019 through 2021			
Circuit	3 yr Average CEMI 4 + Customer Count	3 yr Average Ranking	Rolling 12 Month CEMI (n)
56-68F1	778	32	13
53-34F3	667	36	12
56-54F1	1701	2	11
56-33F4	1564	3	11
53-126W50	1551	4	11
53-21F1	304	62	11
56-155F8	1237	9	10
56-88F3	715	34	10
56-88F1	659	38	10
56-155F6	435	51	10
53-26W7	124	96	10
56-85T1	1708	1	9
56-63F6	1309	6	9
56-86F1	1273	7	9
56-30F2	1129	14	9
56-59F3	520	47	9
56-46F2	242	72	9
56-17F2	1204	12	8
56-155F2	1104	15	8
53-34F1	1042	23	8
53-112W44	651	39	8
53-38F1	595	41	8
56-52F1	1505	5	7
53-127W40	1138	13	7
56-155F4	1074	20	7
56-37W5	1071	21	7
56-42F1	783	31	7
53-45F2	686	35	7
53-127W41	340	60	7
56-68F2	315	61	7
56-88F5	190	78	7
53-48F3	188	79	7
53-1201W2	83	113	7
56-59F1	61	122	7
53-21F2	57	125	7

Division 3-20
CEMI-4 Program

Request:

On page 143, the Company discusses meeting the EEI first quartile performance target of 4.67% which is based on 2020 results (Table 3). RIE then assumes that 4.67% of Rhode Island customers would be targeted for improved CEMI, adjusted by a 30% factor, resulting in a total of 45,0000 customers for targeted work (9,000 per year).

a. How is the 4.67% target calculated?

b. Why did RIE choose 2020 EEI results as a single metric?

c. Is 4.67% a static target or does it change based on actual EEI reporting results each year? If changing annually, what are the EEI quartile performance results for 2017, 2018, 2019, 2021 and 2022?

d. Explain in detail how RIE derived a 30% adjustment factor to account for variability in additional customers that are impacted each year. Why does RIE assume that more customers will be impacted rather than less?

Response:

a. The 4.67 % is the threshold for EEI first quartile performance. CEMI 4 + performance above 4.67 % of customers served is outside of the first quartile.

b. RIE selected 2020 as the representative year because it was a relatively stable reliability year. That is, there were no widespread weather events or storms that would create data anomalies. In fact, the SAIFI for participating EEI companies for all events has been close to 1.00 for the last three years.

c. RI Energy's goal is to be a first quartile CEMI 4 performer. The 4.67 % customer service number is significant only in the sense that it creates a target. At the start of the program, RI Energy's average three year performance was 11.46 %. There is significant room for improvement to meet the 1st quartile performance regardless of the year used to create the target. However, RIE anticipates an alignment between the performance year and the survey year as the program matures.

Division 3-20, page 2
CEMI-4 Program

d. For the program's test years (2019 through 2021), 195 unique circuits appeared on the CEMI 4 + list. Of those, approximately 25 % (48 /195) appeared on the list for 3 consecutive years and 52 % of the circuits appear on the list 2 out of 3 years. Approximately half of RI Energy CEMI 4 + circuits appear on the list only one out the three test years. Meaning approximately ½ of all CEMI 4 customers each year will be new. This is the uncontrolled population of customers contributing to the CEMI 4 + count annually. Therefore, to achieve the program's goal of first quartile performance, RIE derived at a 30% adjustment factor to eliminate CEMI 4 customer contributions from known problem circuits. This provides a reasonable variance in year-of-year performance. RIE does not assume that customer counts on chronically poor CEMI 4 circuits would improve if work was delayed.

Division 3-21
CEMI-4 Program

Request:

In executable format, provide all workpapers and assumptions used to determine the FY 2024 and FY 2025 CEMI-4 program final circuit selections, recommended circuit improvements including alternatives considered, and cost estimates for proposed work.

Response:

The circuit selection for the CEMI-4 program is described in Section 4 of the CEMI program document. A query is run on the outage database to gather the CEMI information per feeder. Attachments DIV 3-21-1A and DIV 3-21-1B contains the information to determine circuit selection for FY 2024 and FY 2025 respectively. Attachment DIV 3-21-2 contains the information for recommended circuit improvements and cost estimates for the proposed work. This should not be considered final costs for FY 2024 efforts nor a complete scope list for FY 2025, but can be used as a guide to understand the appropriateness of the program values. As described in Section 4.2 of the CEMI program document (pages 144 and 145), due to the specific locational and cause characteristics of the events, the CEMI program does not undergo a typical alternative analysis.

Attachments DIV 3-21

The Company provided the following attachments in Excel versions:
Attachment DIV 3-21-1A, Attachment DIV 3-21-1B, and Attachment DIV 3-21-2

Prepared by or under the supervision of: Ryan Constable

Division 3-22
CEMI-4 Program

Request:

Provide a list of each circuit proposed for work under the CEMI-4 program in FY 2024 and FY 2025 with the following:

a. Area Study region
b. Substation
c. Voltage
d. Circuit length (miles of 1 phase, 2 phase, 3 phase and total for overhead and underground)
e. Number of customers served
f. Miles of off-road exposure
g. Whether the circuit has town priorities or critical customers
h. Area Study system improvements planned for the substation or circuit and implementation timeline
i. A list of each outage in the current and previous three years separated by non-storm and storm
j. Outage cause, indicating mainline or tap line, overhead or underground
k. Duration of each outage
l. Circuit map showing the location of each outage
m. How many times the circuit was included in the 5% of worst performing circuits on the basis of customer frequency for any quarter in the past five years (Docket 3628 – Rhode Island Energy Service Quality Plan). For each, identify the quarter/year and provide the associated quarterly Feeder Ranking Report.
n. Circuit SAIDI and Circuit SAIFI, with and without storms, for the previous five years
o. Whether outage was in a location with excessive tree exposure or denials for tree removals
p. Number of restoration steps for each outage
q. Corrective actions taken to restore each outage including improvement work performed at time of outage and cost
r. Most recent year of vegetation management cycle trimming and hazard tree removals completed on the affected circuit
s. Next planned year for vegetation management and hazard tree removals for the affected circuit
t. Whether the circuit has received off-cycle vegetation management and when (e.g. pockets of poor performance or other)
u. The RIE root cause analysis of each outage with a list of solution alternatives, identifying the least cost solution to remediate the outage

Division 3-22, page 2
CEMI-4 Program

v. The proposed work list and estimated costs for RIE's recommended solution set in an executable format consistent with Appendix A (page 149), identifying any proposed investments that are GMP related such as FLISR.

Response:

Attachment DIV 3-22-1 contains the following information for each circuit under the CEMI 4 program:

a. Area Study region
b. Substation
c. Voltage
d. Circuit length (miles of 1 phase, 2 phase, 3 phase and total for overhead and underground)
e. Number of customers served
h. Area Study system improvements planned for the substation or circuit. Planned area system improvement timelines are listed in the proposed ISR filing.
i. A list of each outage in the current and previous three years separated by non-storm and storm
j. Outage cause, indicating mainline or tap line, overhead or underground
k. Duration of each outage
n. Circuit SAIDI and Circuit SAIFI, with and without storms, for the previous five years
p. Number of restoration steps for each outage
r. Most recent year of vegetation management cycle trimming and hazard tree removals completed on the affected circuit
s. Next planned year for vegetation management and hazard tree removals for the affected circuit
t. Whether the circuit has received off-cycle vegetation management and when (e.g. pockets of poor performance or other)

Attachment DIV 3-22-2 contains the following information:

l. A example circuit map with two data sets for the Coventry 54F1 circuit. In the proposed FY25 ISR plan on page144, Section 4.2 Consultation and Design of CEMI program document, mapping is referenced as follows: "To the furthest extent possible, the damage locations should be mapped. With an understanding of customer, damage locations and protective device locations, solutions will be developed." This statement should not be interpreted as the literal creation of a map because it is largely a manual process done by

CEMI-4 Program

the Field Engineer during project scoping. The datasets used to create the maps (list of customer addresses with high CEMI, outages contributing to the CEMI count, and a GIS display of the circuit with a background street map are not digitally connected, making it cumbersome to effectively display. Typically, the Engineer will work with all three data sets simultaneously to determine a list of trouble spots for field investigation.

The following items are not provided with an explanation:

f. *Miles of off-road exposure*. Off road line miles is not a readily available data point that can be listed on a spreadsheet. However, it is considered during the individual circuit review.

g. *Whether the circuit has town priorities or critical customers.* Town priorities and critical customer information is informally gathered through the area Field Engineer's experience and through consultation with community representatives.

m. *How many times the circuit was included in the 5% of worst performing circuits on the basis of customer frequency for any quarter in the past five years (Docket 3628 – Rhode Island Energy Service Quality Plan). For each, identify the quarter/year and provide the associated quarterly Feeder Ranking Report.* The Company has explained is separate discussions that the quarterly reports should not be used for reliability program review as they only contain the 5% worst performing feeders for that quarter. Additionally, the quarterly reports add no value to a CEMI program review. Item n, provides the outage data that can be used for a CEMI program review.

o. *Whether outage was in a location with excessive tree exposure or denials for tree removals.* CEMI-4 circuits are located within the state's most densely populated tree areas. Towns with CEMI-4 circuits include West Greenwich, Charlestown Westerly, Tiverton North Smithfield, and Burrillville. The Company does not keep a formal database for tree trimming request that were denied by private property owner. Consultation with Forestry did not recollect denials for tree removal in the CEMI-4 towns.

q. *Corrective actions taken to restore each outage including improvement work performed at time of outage and cost.* The actions taken to immediately restore interrupted customers are noted on the outage comments on the attached spreadsheet. In most cases, a single repair is made to restore power at the time of the outage. The cost of adhoc repairs is not tracked on a per job basis.

u. *The RIE root cause analysis of each outage with a list of solution alternatives, identifying the least cost solution to remediate the outage.* A root cause analysis, alternative analysis, and solution development of every outage is not performed as it would result in an inefficient use of resources. For the CEMI work, the engineer gathers all the outages and their causes and then evaluates the most appropriate solution for the grouped outages.

Division 3-22, page 4
CEMI-4 Program

A formal alternative analysis is not performed as described in Section 4.2 of the CEMI document (pages 144 and 145). Instead, the engineer progresses through a set of low cost to higher cost options. Attachment DIV 3-22-3 includes an example document that demonstrates the evaluation of a set of outages and development of solutions. The engineer reviews a number of maps and datasets simultaneously as described in item l above. This document does not contain screens captures of the various screen the engineer uses to complete the work.

v. *The proposed work list and estimated costs for RIE's recommended solution set in an executable format consistent with Appendix A (page 149), identifying any proposed investments that are GMP related such as FLISR.* Please see Attachment DIV 3-21-2. All mainline reclosers will be incorporated into a FLISR scheme as soon as practical. Also see the response to Division 3-31.

Attachment DIV 3-22-1 and Attachment DIV 3-22-2

The Company provided an Excel version of Attachment DIV 3-22-1 and Attachment DIV 3-22-2

Rhode Island Energy™
a PPL company

Memorandum – CEMI and ERR – Feeder 56-155F8

To: Eric Wiesner

From: Mark Fraser

Date: July 13, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 56-155F8

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 56-155F8 feeder out of Chase Hill Substation.

RELIABILITY PERFORMANCE

RIE System SAIFI				
2022	2021	2020	2019	2018
2.7	3.0	3.1	3.6	2.9

					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
56-155F8	13	1955	OH	23.27	126.9	155.7	99.0	331.5	1195.7

RIE System SAIFI				
2022	2021	2020	2019	2018
2.7	3.0	3.1	3.6	2.9

					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
56-155F8	13	1955	OH	23.27	1.95	2.05	1.61	2.95	11.60

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 56-155F8

Date	Location	Cause	Town	Estimated CKAIFI	Estimated CKAIDI Min
8/22/2021	56-155F8: JEA: FAIRVIEW AVE (0410)	Tree Fell	HOPKINTON	0.91	2,959.9
3/2/2018	56-155F8: JEA: FAIRVIEW AVE (0410)	Tree Fell	EXETER	0.94	2,143.0
3/13/2018	56-155F8: K: MAIN ST (0590)	Tree Fell	RICHMOND	1.12	1,107.4
2/7/2020	56-155F8: N: BITGOOD RD (0050)	Tree Fell	RICHMOND	1.06	1,009.4
11/1/2019	56-155F8: G: MAIN ST (0590)	Tree - Broken Limb	HOPKINTON	0.99	894.9
3/2/2021	56-155F8: G: MAIN ST (0590)	Tree Fell	HOPKINTON	0.84	408.7
8/22/2021	56-155F8: M: ARCADIA RD (0050)	Tree - Broken Limb	RICHMOND	0.10	337.7
3/2/2018	56-155F8: LA: ARCADIA RD (0050)	Tree Fell	HOPKINTON	0.08	245.5
3/2/2018	56-155F8: M: ARCADIA RD (0050)	Unknown	HOPKINTON	0.06	224.5
8/4/2020	56-155F8: LAJ: SKUNK HILL RD (0820)	Unknown	HOPKINTON	0.08	201.0
3/4/2019	56-155F8: E: 85T2 LINE RWAY (0051)	Tree Fell	RICHMOND	1.05	191.5
10/17/2019	56-155F8: HE: HIGHVIEW AVE (0590)	Tree - Broken Limb	RICHMOND	0.08	162.5
8/4/2020	56-155F8: HIAG: BROOK DR (0992)	Unknown	HOPKINTON	0.05	125.5
11/1/2019	56-155F8: LAJ: SKUNK HILL RD (0820)	Tree - Broken Limb	HOPKINTON	0.08	122.5
3/2/2018	56-155F8: IBHJA: CANONCHET RD (0210)	Tree Fell	HOPKINTON	0.02	109.0
3/13/2018	56-155F8: KA: MAIN ST (0940)	Vehicle	EXETER	0.54	104.1
2/7/2020	56-155F8: LA: ARCADIA RD (0050)	Insulation failure - other	HOPKINTON	0.08	99.3
11/5/2018	56-155F8: A: 85T2 LINE#2 RWAY (0051)	Tree - Broken Limb	RICHMOND	1.07	95.2
8/7/2019	56-155F8: J: MAIN ST (0590)	Tree Fell	HOPKINTON	1.38	92.3
6/7/2021	56-155F8: G: MAIN ST (0590)	Tree Fell	RICHMOND	1.00	91.2
10/17/2019	56-155F8: LA: ARCADIA RD (0050)	Unknown	HOPKINTON	0.03	86.1
11/3/2018	56-155F8: A: 85T2 LINE#2 RWAY (0051)	Unknown	HOPKINTON	0.93	85.6
8/4/2020	56-155F8: HEAE: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.03	78.5
10/27/2021	56-155F8: IBHK: SPRING ST (0833)	Tree Fell	HOPKINTON	0.04	55.0
10/27/2021	56-155F8: HJ: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.03	50.0
5/10/2020	56-155F8: G: MAIN ST (0590)	Tree Fell	RICHMOND	1.44	49.0
3/2/2021	56-155F8: HI: FENNER HILL RD (0420)	Unknown	HOPKINTON	0.11	42.8
3/29/2019	56-155F8: A: 85T2 LINE#2 RWAY (0051)	Vehicle	HOPKINTON	1.07	38.8
8/4/2020	56-155F8: IBHK: SPRING ST (0833)	Tree - Broken Limb	HOPKINTON	0.01	35.6
3/2/2021	56-155F8: M: ARCADIA RD (0050)	Tree Fell	EXETER	0.05	34.4
8/4/2020	56-155F8: IBHCF: WOODY HILL RD (0360)	Unknown	HOPKINTON	0.01	33.1
3/2/2018	56-155F8: IBHK: SPRING ST (0833)	Tree Fell	HOPKINTON	0.01	32.0
11/12/2021	56-155F8: G: MAIN ST (0590)	Tree Fell	RICHMOND	1.01	31.7
2/18/2022	56-155F8: HI: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.11	23.1
2/24/2023	56-155F8: L: BRIDGE ST (0050)	Tree Fell	HOPKINTON	0.23	22.1
2/27/2021	56-155F8: LA: ARCADIA RD (0050)	Device Failed	HOPKINTON	0.12	14.7
1/18/2022	56-155F8: A: 85T2 LINE#2 RWAY (0051)	Tree - Broken Limb	EXETER	1.01	10.7
11/15/2020	56-155F8: HE: HIGHVIEW AVE (0465)	Tree Fell	RICHMOND	0.11	9.5
7/25/2022	56-155F8: HI: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.11	7.8
12/4/2022	56-155F8: HE: HIGHVIEW AVE (0590)	Device Failed	RICHMOND	0.11	7.1
4/7/2022	56-155F8: HI: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.11	6.0
8/22/2021	56-155F8: HI: FENNER HILL RD (0420)	Tree - Broken Limb	HOPKINTON	0.11	5.4
1/25/2018	56-155F8: I: MAIN ST (0590)		EXETER	1.17	5.3
12/1/2022	56-155F8: HE: HIGHVIEW AVE (0590)	Tree Fell	HOPKINTON	0.11	2.6
12/4/2020	56-155F8: HE: HIGHVIEW AVE (0590)	Tree Fell	HOPKINTON	0.11	0.8
3/26/2022	56-155F8: IB: SPRING ST (0833)	Vehicle	HOPKINTON	0.22	0.7

Completed Work

Over the last five years, 34 reliability Work Requests have been completed. These include pole upgrades, transformer installations, removal of pin insulators, a capacitor bank installation, and the addition of regulators.

City/Town Description	Feeder Number (Location ID)	WR Number	WR Status Code	Work Request Description	Job Type Code
HOPE VALLEY	56-155F8	30713912	80	Pole 10: Replace OLT w new 50kva fused @15k	DASSETREPL
HOPKINTON	56-155F8	28394274	90	REPLACE OPEN WIRE SECONDARY W/ 1/0 TRIPLEX	DASSETREPL
HOPKINTON	56-155F8	28394332	90	REPLACE OPEN WIRE SECONDARY W/ 1/0 TRIPLEX FROM PL 8 TO PL 8-2	DASSETREPL
HOPKINTON	56-155F8	30362002	90	COUNTRY LANDS CABLE INJECTION	DASSETREPL
HOPKINTON	56-155F8	30732101	80	Replace Pole 1	DASSETREPL
HOPKINTON	56-155F8	30732141	80	Replace Pole 5	DASSETREPL
HOPKINTON	56-155F8	30734252	80	replace pole, xfmr/install new stub pole/anchor/rmv tree guy	DASSETREPL
RICHMOND	56-155F8	27591998	90	Replace pole/anchor corner of nooseneck/main street - in front of stagecoach	DASSETREPL
RICHMOND	56-155F8	28169676	90	replace pole 4 & anchor, trasnfer DE Pri/sec/oh xfmr, service wire	DASSETREPL
RICHMOND	56-155F8	30561607	90	Replace damaged P83-1	DASSETREPL
HOPE VALLEY	56-155F8	28054470	90	Replace Pole 5-4 with new 35'C3 pole and install anchor	DDAMAGE
HOPE VALLEY	56-155F8	30677826	90	replace pole 28-4 & install anchor	DDAMAGE
HOPKINTON	56-155F8	28521783	90	Replace Pole 17-1, anchor and Guy	DDAMAGE
HOPKINTON	56-155F8	28522105	90	replace pole 17 w 45'C2 pole	DDAMAGE
HOPKINTON	56-155F8	29720082	90	Replace;4 damaged Poles w 40'C3 poles, xfmr, 2 cutouts. transfer 1ph pri & sec	DDAMAGE
HOPKINTON	56-155F8	29731382	90	Replace Pole, anchor & guy, cutout, install LA.	DDAMAGE
HOPKINTON	56-155F8	29832907	90	replace 3 poles & 3 pole top cross arms and insulators.	DDAMAGE
HOPKINTON	56-155F8	30124273	90	replace pole 8 and xfmr install new stub pole 8-84/anchor	DDAMAGE
HOPKINTON	56-155F8	30389578	90	Pole 18: replace push brace	DDAMAGE
HOPKINTON	56-155F8	30458519	90	replace pole 67 w new 40'C3 - storm damage -	DDAMAGE
HOPKINTON	56-155F8	30743607	40	install stub pole, replace 3 secondary poles, replace service wire.	DDAMAGE
EXETER	56-155F8	29624376	50	PL 71 SUMMIT RD - REPLACE 25 KVA WITH 50 KVA 120/240 V 7.2 KV XFMR	DLOADRELF
EXETER	56-155F8	29640639	90	PL 8-4 KENNEY HILL RD - UPGRADE POLE AND XFMR	DLOADRELF
HOPKINTON	56-155F8	29720156	90	Pole 5; replace pole, replace olt	DLOADRELF
RICHMOND	56-155F8	30538696	90	Install Feeeder Tie L/B and Perform Switching	DLOADRELF
HOPE VALLEY	56-155F8	28091882	90	Replace Pin Insulators	DMAINT-G
HOPE VALLEY	56-155F8	28316673	90	Replace Pin Insulators	DMAINT-G
HOPE VALLEY	56-155F8	28316691	90	Replace Pin Insulators	DMAINT-G
HOPE VALLEY	56-155F8	28316708	90	Replace Pin Insulators	DMAINT-G
HOPE VALLEY	56-155F8	28316719	90	Replace Pin Insulators	DMAINT-G
HOPE VALLEY	56-155F8	27424511	90	remove tree guy, install new stub pole, anchor & guy, pole to pole guy.	DRELIABLE
HOPKINTON	56-155F8	28204267	80	replace 1 pole & section of sec, install anchor	DRELIABLE
HOPKINTON	56-155F8	28236550	90	replace pole 16 with new 40'C3 pole.	DRELIABLE
HOPKINTON	56-155F8	30629275	60	155F8 Whispering Pines Work - Line Regulators and Cap Banks	DRELIABLE

Pending Work

There are no open reliability work requests from 2022 and prior.

2023 Recommendations

These recommendations reflect both short-term projects and possible long-term improvements.

Title/Description	Category	Est. Cost	Storms WO	Status	Cust	Es. Cust. Min. Saved
Replace 3-65K fuses with 3-65K CMRs at P44 Arcadia Road, Hopkinton.	CEMI	$16,629	30792008	In Progress	128	6,144
Install a 40K CMR on Phase B (RH) and a 40K fuse on Phase C (LH) at P7 Arcadia Road. Review P1 Arcadia Road to confirm there is no C/O. Hopkinton	CEMI	$12,000		To Be Designed	102	2,448
The ROW off of Ashway Road heading south west only serves 132 customer and creates 4,400 feet of exposure to the 1,925 customer on the circuit. This line should be removed and the customers pick up from the 155W6 or the 155W4. Further study required.	ERR			Under Engineering Review		
ROW P1067 found to be leaning. Operations to staighten pole.	ERR					
Replace 40K fuse at P44 Farview Avenue with a 40K CMR. Add mainline cutout at P24 Fairview Avenue. Fuse mainline and tap to Clarke Ave with 25K fuses.	ERR	$15,000		To Be Designed	107	3,414
At P47 Main Street, upgrade lower arm on pole top to separate north and south taps. Install three 65K fuses looking toward P26 Highview Ave. Install three line insultors looking toward P25-50 Highview Ave. Create new tap on phase C (Left Hand) and install 65K CMR. Remove C/O and tap over at P25 Highview Ave.	ERR	$20,000		To Be Designed	158	14,620
Replace 40K fuse at P70 Fenner Hill Road with a 40K CMR. Hipkinton.	ERR	$10,000		To Be Designed	60	3,168
Upon replace of the 635033 PTR at P40 Main St, the new PTR should be placed near P32 Main St, the existing location of a LBS. This would put this device beyond the Spring Street tap with 426 customers. There is a PTR there currently and the minimal addition exposure would greatly reduce the existing exposure to these customers for fault on Main Street.	ERR	$83,000		To Be Designed	1,162	

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in March of 2021.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Over the last five years, there have only been thirteen outages linked to animal contacts representing less than 2% of the customer minutes during that period.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
A load shift is proposed above to reduce exposure.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations:
See the recommendations above.

Additional Circuit Sectionalizing:
Not at this time.

Additional Feeder Ties/Reconfiguration:
Should the ROW line be removed as suggested above, improved ties should be considered.

Protective Device Coordination Review:
Not necessary at this time.

Other Recommendations:
None

Division 3-23

CEMI-4 Program

Request:

If a line recloser without FLISR is proposed in a solution set, will the recloser have remote operation? If yes, explain why that remote operation capability is necessary and the cost associated with that feature.

Response:

All proposed reclosers are mainline reclosers and will include remote operation and be incorporated into a FLISR scheme as soon as possible. For approximately the past 5 years, the Company's standard mainline recloser included remote operation capability. The Company does not have a mainline recloser type without the communication package to present a difference in cost.

Division 3-24
CEMI-4 Program

Request:

The Company states that the inputs shown in Table 8 (page 146) "were a frequency per year improvement of 4 to 1 with each interruption assumed to be 4 hours or 240 minutes." Please clarify that the Company is assuming that every customer on each circuit in the CEMI-4 program will experience 3 fewer interruptions per year for 20 years once proposed improvements are implemented. If so, explain the basis for this assumption and provide support. Also explain the basis and provide support for the assumption that each interruption is 240 minutes.

Response:

Yes, the Company is assuming that the CEMI customers will experience 3 fewer interruptions per year for 20 years once the proposed improvements are implemented for the benefit/cost analysis. This is a conservative assumption as there are customers with CEMI values greater than 4. Also see the response to Division 3-9. The basis for this assumption is to drive the CEMI customers closer to the system average. The scope is then established to achieve this frequency reduction. Animal guards and tree resistant construction can eliminate some outage cause, while cutout mounted reclosers and mainline reclosers incorporated into a FLISR scheme can significantly mitigate other outages. Although the system average frequency is less than 1, the CEMI program is an attempt to get the CEMI customer close to, but not equal to the system average.

240 minutes, or a 4 hour outages, is a typical planning assumption. It is used for many general reliability and contingency calculations. A cursory review of 2021 and 2022 fuse, service transformer, and secondary outages shows an average duration of 336 minutes per event, which demonstrates the 240 minute conservative assumption for benefit/cost analysis is appropriate.

Division 3-25
CEMI-4 Program

Request:

Do the benefits in Table 10 (page 147) assume that all 45,000 customers will experience reliability improvements starting with the first year? If not, please revise the table to reflect the expected customer counts each year.

Response:

As an initial matter, the Company found an error in Table 10 (page 147) where the discount rate was not properly applied to the cost cash flow. A revised Table 10 (Table 10A) is shown below with the discount rate applied to the cost cash flow, note that the benefit-cost assessment still results in a benefit-cost ratio greater than one.

Yes, Table 10 (page 147) and Table 10A (below) assume that all 45,000 customers will experience reliability improvements starting with the first year. This was a simplifying assumption to create a simple 20-year evaluation from 2023 to 2042. When staggering the customer counts, the evaluation period extends to 2046, which is 20 years past the fifth year of deployment. If the Company truncated the staggered analysis to a 20-year time frame to be consistent with the analysis presented in Tables 10 and 10A, then the benefit-cost assessment result in a benefit-cost ratio of 1.67. Note that this truncated analysis omits benefits in year 2043-2046 and therefore provides an underestimated benefit-cost ratio.

The Company shows this staggered customer sensitivity analysis for the full time period 2023-2046 in Table 10B, below. In this sensitivity scenario, the benefit-cost ratio is greater than one. The benefit-cost ratio in Table 10B is larger than the benefit-cost ratio in Table 10A because of the additional years included to account for a 20-year impact for customers starting in year 4.

In conducting sensitivity analyses like these, the Company points to the key conclusion that the benefit cost ratio is greater than one across a variety of scenarios and is, therefore, relatively insensitive to assumptions about how affected customers are modeled. The Company has also considered alternative qualitative sensitivity analyses for other inputs to and assumptions in the benefit-cost assessment. For example, the Company highlights that it assumed a reduction in interruptions of three interruptions per customer for all CEMI customers. This assumption is a lower bound because there are customers (e.g., CEMI-10) that see a larger reduction in interruptions than assumed in the benefit-cost assessment (e.g., nine interruptions). This sensitivity analysis results in a benefit-cost ratio greater than one and larger than the benefit-cost ratios presented in Table 10, 10A, and 10B; therefore, the conclusion of this sensitivity analysis is that benefits outweigh costs even when taking a lower bound estimate of number of interruptions reduced.

Division 3-25, page 2
CEMI-4 Program

Table 10A Revised – Corrected Cost Cash Flow

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$1,779,970	$444,992	$1,562,278		2023	$1,300,000
2024	$1,815,569	$453,892	$1,825,371		2024	$5,312,000
2025	$1,851,880	$462,970	$2,098,363		2025	$4,546,832
2026	$1,888,918	$472,230	$2,381,544		2026	$4,683,237
2027	$1,926,696	$481,674	$2,675,213		2027	$4,823,734
2028	$1,965,230	$491,308	$2,728,717		2028	
2029	$2,004,535	$501,134	$2,783,291		2029	
2030	$2,044,626	$511,156	$2,838,957		2030	
2031	$2,085,518	$521,380	$2,895,736		2031	
2032	$2,127,228	$531,807	$2,953,651		2032	
2033	$2,169,773	$542,443	$3,012,724		2033	
2034	$2,213,169	$553,292	$3,072,978		2034	
2035	$2,257,432	$564,358	$3,134,438		2035	
2036	$2,302,581	$575,645	$3,197,127		2036	
2037	$2,348,632	$587,158	$3,261,069		2037	
2038	$2,395,605	$598,901	$3,326,291		2038	
2039	$2,443,517	$610,879	$3,392,817		2039	
2040	$2,492,387	$623,097	$3,460,673		2040	
2041	$2,542,235	$635,559	$3,529,886		2041	
2042	$2,593,080	$648,270	$3,600,484		2042	
NPV			$32,960,282			$18,110,970
Benefit - Cost						$14,849,311
Benefit/Cost						1.82

Division 3-25, page 3
CEMI-4 Program

Table 10B Revised – Corrected Cost Cash Flow and Staggered Customers

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$355,994	$88,998	$494,297		2023	$1,300,000
2024	$726,228	$181,557	$1,008,365		2024	$5,312,000
2025	$1,111,128	$277,782	$1,542,799		2025	$4,546,832
2026	$1,511,134	$377,784	$2,098,206		2026	$4,683,237
2027	$1,926,696	$481,674	$2,675,213		2027	$4,823,734
2028	$1,965,230	$491,308	$2,728,717		2028	
2029	$2,004,535	$501,134	$2,783,291		2029	
2030	$2,044,626	$511,156	$2,838,957		2030	
2031	$2,085,518	$521,380	$2,895,736		2031	
2032	$2,127,229	$531,807	$2,953,651		2032	
2033	$2,169,773	$542,443	$3,012,724		2033	
2034	$2,213,169	$553,292	$3,072,978		2034	
2035	$2,257,432	$564,358	$3,134,438		2035	
2036	$2,302,581	$575,645	$3,197,127		2036	
2037	$2,348,632	$587,158	$3,261,069		2037	
2038	$2,395,605	$598,901	$3,326,291		2038	
2039	$2,443,517	$610,879	$3,392,817		2039	
2040	$2,492,387	$623,097	$3,460,673		2040	
2041	$2,542,235	$635,559	$3,529,886		2041	
2042	$2,593,080	$648,270	$3,600,484		2042	
2043	$2,644,941	$661,235	$3,672,494		2043	
2044	$2,697,840	$674,460	$3,745,944		2044	
2045	$2,751,797	$687,949	$3,820,862		2045	
2046	$2,806,833	$701,708	$3,897,280		2046	
NPV			$34,716,790			$18,110,970
Benefit - Cost						$16,605,820
Benefit/Cost						1.92

Division 3-26
CEMI-4 Program

Request:

Confirm that the additional benefit of $28,000 per year per feeder assumes one mainline recloser installation on a circuit and excludes three reclosers with a FLISR scheme.

Response:

The additional $28,000 per year per feeder is associated with the additional two to three reclosers for a FLISR scheme on the entire feeder. There are one to two reclosers included in the base CEMI analysis and base cost ($2.6 million), which may be incorporated into a limited FLISR scheme.

Division 3-27
CEMI-4 Program

Request:

What inflation rate and discount rate did the Company assume in the USDOE ICE calculator and why?

Response:

The Company used the default ICE calculator values of 2% for inflation rate and 6% for the discount rate. They were used as simple default values.

Division 3-28
CEMI-4 Program

Request:

Provide the cost and benefit information in Table 10 (page 147) for the three scenarios below. Identify all assumptions and inputs used in deriving both costs and benefits:

a. CEMI-4 program assuming all proposed work but excluding reclosers and FLISR;

b. CEMI-4 program assuming all proposed work including line reclosers but excluding reclosers with FLISR schemes;

c. CEMI-4 program assuming all proposed work including all reclosers and FLISR.

Response:

This response incorporates the response to Division 3-25 which requests that Table 10 be revised to reflect the expected customer count per year. An error was also found in Table 10 (page 147) where the discount rate was not properly applied to the cost cash flow. A revised Table 10 (Table 10-1) is shown below with the discount rate applied to the cost cash flow.

All tables use the following assumptions:

- Evaluation period = 20 years
- Inflation Rate = 2% (Default, also see the response to Division 3-27.)
- Discount Rate = 6% (Default, also see the response to Division 3-27.)
- SAIFI improvement from 4 to 1. (Also see the response to Division 3-24.)
- CAIDI = 240 minutes (Also see the response to Division 3-24.)
- Customers = 9,000 residential customers per year for 5 years

a. Table 10-1A below shows the analysis for a CEMI-4 program assuming all proposed work but excluding reclosers and FLISR. This table is provided as requested, but this analysis assumes the reclosers to achieve the CEMI goals are included in another program. The CEMI goals cannot be achieved without some reclosers, which may or may not be incorporated into a FLISR scheme.

b. Table 10-1B shows the analysis for a CEMI-4 program assuming all proposed work including line reclosers but excluding reclosers with FLISR schemes.

c. Table 10-1C shows the analysis for a CEMI-4 program assuming all proposed work including all reclosers and FLISR. This table includes a transferred benefit from the

Division 3-28, page 2
CEMI-4 Program

Distribution Automation Recloser Program of approximately $28,000 per feeder. Also see the response to Division 3-26.

Table 10-1 Revised – Corrected Cost Cash Flow

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$1,779,970	$444,992	$1,562,278		2023	$1,300,000
2024	$1,815,569	$453,892	$1,825,371		2024	$5,312,000
2025	$1,851,880	$462,970	$2,098,363		2025	$4,546,832
2026	$1,888,918	$472,230	$2,381,544		2026	$4,683,237
2027	$1,926,696	$481,674	$2,675,213		2027	$4,823,734
2028	$1,965,230	$491,308	$2,728,717		2028	
2029	$2,004,535	$501,134	$2,783,291		2029	
2030	$2,044,626	$511,156	$2,838,957		2030	
2031	$2,085,518	$521,380	$2,895,736		2031	
2032	$2,127,228	$531,807	$2,953,651		2032	
2033	$2,169,773	$542,443	$3,012,724		2033	
2034	$2,213,169	$553,292	$3,072,978		2034	
2035	$2,257,432	$564,358	$3,134,438		2035	
2036	$2,302,581	$575,645	$3,197,127		2036	
2037	$2,348,632	$587,158	$3,261,069		2037	
2038	$2,395,605	$598,901	$3,326,291		2038	
2039	$2,443,517	$610,879	$3,392,817		2039	
2040	$2,492,387	$623,097	$3,460,673		2040	
2041	$2,542,235	$635,559	$3,529,886		2041	
2042	$2,593,080	$648,270	$3,600,484		2042	
NPV			$32,960,282			$18,110,970
Benefit - Cost						$14,849,311
Benefit/Cost						1.82

Division 3-28, page 3

CEMI-4 Program

Table 10-1A – CEMI-4 program assuming all proposed work but excluding reclosers and FLISR[1]

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$355,994	$88,998	$266,995		2023	$1,300,000
2024	$726,228	$181,557	$544,671		2024	$1,600,000
2025	$1,111,128	$277,782	$833,346		2025	$1,632,000
2026	$1,511,134	$377,784	$1,133,351		2026	$1,664,640
2027	$1,926,696	$481,674	$1,445,022		2027	$1,697,933
2028	$1,965,230	$491,308	$1,473,923		2028	
2029	$2,004,535	$501,134	$1,503,401		2029	
2030	$2,044,626	$511,156	$1,533,469		2030	
2031	$2,085,518	$521,380	$1,564,139		2031	
2032	$2,127,229	$531,807	$1,595,421		2032	
2033	$2,169,773	$542,443	$1,627,330		2033	
2034	$2,213,169	$553,292	$1,659,876		2034	
2035	$2,257,432	$564,358	$1,693,074		2035	
2036	$2,302,581	$575,645	$1,726,935		2036	
2037	$2,348,632	$587,158	$1,761,474		2037	
2038	$2,395,605	$598,901	$1,796,704		2038	
2039	$2,443,517	$610,879	$1,832,638		2039	
2040	$2,492,387	$623,097	$1,869,290		2040	
2041	$2,542,235	$635,559	$1,906,676		2041	
2042	$2,593,080	$648,270	$1,944,810		2042	
2043	$2,644,941	$661,235	$1,983,706		2043	
2044	$2,697,840	$674,460	$2,023,380		2044	
2045	$2,751,797	$687,949	$2,063,848		2045	
2046	$2,806,833	$701,708	$2,105,125		2046	
NPV			$18,752,354			$7,004,494
Benefit - Cost						$11,747,860
Benefit/Cost						2.68

[1] This table is not achievable without other recloser investments.

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CEMI-4 Program

Table 10-1B – CEMI-4 program assuming all proposed work including line reclosers but excluding reclosers with FLISR schemes

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$355,994	$88,998	$266,995		2023	$1,300,000
2024	$726,228	$181,557	$544,671		2024	$2,600,000
2025	$1,111,128	$277,782	$833,346		2025	$2,652,000
2026	$1,511,134	$377,784	$1,133,351		2026	$2,705,040
2027	$1,926,696	$481,674	$1,445,022		2027	$2,759,141
2028	$1,965,230	$491,308	$1,473,923		2028	
2029	$2,004,535	$501,134	$1,503,401		2029	
2030	$2,044,626	$511,156	$1,533,469		2030	
2031	$2,085,518	$521,380	$1,564,139		2031	
2032	$2,127,229	$531,807	$1,595,421		2032	
2033	$2,169,773	$542,443	$1,627,330		2033	
2034	$2,213,169	$553,292	$1,659,876		2034	
2035	$2,257,432	$564,358	$1,693,074		2035	
2036	$2,302,581	$575,645	$1,726,935		2036	
2037	$2,348,632	$587,158	$1,761,474		2037	
2038	$2,395,605	$598,901	$1,796,704		2038	
2039	$2,443,517	$610,879	$1,832,638		2039	
2040	$2,492,387	$623,097	$1,869,290		2040	
2041	$2,542,235	$635,559	$1,906,676		2041	
2042	$2,593,080	$648,270	$1,944,810		2042	
2043	$2,644,941	$661,235	$1,983,706		2043	
2044	$2,697,840	$674,460	$2,023,380		2044	
2045	$2,751,797	$687,949	$2,063,848		2045	
2046	$2,806,833	$701,708	$2,105,125		2046	
NPV			$18,752,354			$10,569,802
Benefit - Cost						$8,182,552
Benefit/Cost						1.77

Division 3-28, page 5

CEMI-4 Program

Table 10-1C – CEMI-4 program assuming all proposed work including all reclosers and FLISR

Year	Interruption Costs Without Improvement (Baseline)	Interruptions Costs With Improvement	Total Benefit		Year	Project Costs
2023	$355,994	$88,998	$494,297		2023	$1,300,000
2024	$726,228	$181,557	$1,008,365		2024	$5,312,000
2025	$1,111,128	$277,782	$1,542,799		2025	$4,546,832
2026	$1,511,134	$377,784	$2,098,206		2026	$4,683,237
2027	$1,926,696	$481,674	$2,675,213		2027	$4,823,734
2028	$1,965,230	$491,308	$2,728,717		2028	
2029	$2,004,535	$501,134	$2,783,291		2029	
2030	$2,044,626	$511,156	$2,838,957		2030	
2031	$2,085,518	$521,380	$2,895,736		2031	
2032	$2,127,229	$531,807	$2,953,651		2032	
2033	$2,169,773	$542,443	$3,012,724		2033	
2034	$2,213,169	$553,292	$3,072,978		2034	
2035	$2,257,432	$564,358	$3,134,438		2035	
2036	$2,302,581	$575,645	$3,197,127		2036	
2037	$2,348,632	$587,158	$3,261,069		2037	
2038	$2,395,605	$598,901	$3,326,291		2038	
2039	$2,443,517	$610,879	$3,392,817		2039	
2040	$2,492,387	$623,097	$3,460,673		2040	
2041	$2,542,235	$635,559	$3,529,886		2041	
2042	$2,593,080	$648,270	$3,600,484		2042	
2043	$2,644,941	$661,235	$3,672,494		2043	
2044	$2,697,840	$674,460	$3,745,944		2044	
2045	$2,751,797	$687,949	$3,820,862		2045	
2046	$2,806,833	$701,708	$3,897,280		2046	
NPV			$34,716,790			$18,110,970
Benefit - Cost						$16,605,820
Benefit/Cost						1.92

Division 3-29
CEMI-4 Program

Request:

RIE states, "when completing the CEMI work, the Company may add other programmatic work, such as FLISR work, to the CEMI feeders for efficiency reasons. This could add 2 to 3 reclosers to each feeder or approximately $1.9M to the yearly cash flow for a total program budget of $4.5M per year." (page 148)

a. What is the incremental benefit that will be achieved for this nearly 70% increase in cost due to FLISR?

b. What are the efficiencies achieved through implementing FLISR now versus deferral to a later date? Detail the cost differentials between FLISR work performed now as compared to later date.

c. What does the Company take in consideration when deciding that it "may" add other programmatic work?

d. What are examples of other programmatic work, rationale for implementation, and costs?

Response:

a. The incremental benefit is the transferred benefit as calculated within the Distribution Automation Recloser Program. It should not be represented as an increase to the CEMI work. Instead, it is a transfer between programs to create work efficiencies and avoid overlap and duplication.

b. The work transferred to the CEMI program was work that would have progressed under the Distribution Automation program. Deferral of the work is expected to result in continued poor reliability performance for the relevant subset of customers and deferral of the benefits.

c. When addressing overlap between programs, the Company takes into consideration the priorities of the programs, the location of the work, and the timing of the work.

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CEMI-4 Program

d. Examples of programmatic work transferred between programs include:

    1. Transferring reliability work between the Distribution Automation, CEMI-4, and Engineering Reliability Review programs.
    2. Transferring 3V0 or electromechanical relay work into EMS projects.
    3. Transferring EMS work into a specific asset condition project.
    4. Incorporating distribution automation reclosers into specific feeder work.
    5. Incorporating advanced capacitors into specific feeder work.

    The rationale for transferring work between programs is simple work efficiency. The work is designed through a single engineering effort, the work is performed without additional mobilization and demobilization efforts, and the work can be performed under common permits, traffic management plans, temporary system reconfigurations, and equipment outage plans.

Division 3-30
CEMI-4 Program

Request:

Is CEMI-4 a reliability program to address circuit specific outages or a recloser sectionalizing program?

Response:

CEMI-4 is a reliability program to address circuit specific outages as described in Sections 2 and 3 of the CEMI-4 program document (Attachment 7).

The response to Division 3-29 explains how recloser sectionalization can be included in the CEMI-4 program.

Division 3-31
CEMI-4 Program

Request:

What additional system(s) must be in place and operating to enable a) line reclosers and b) reclosers with FLISR schemes? Provide a description of the systems, implementation cost, and timeline.

Response:

As part of the transition to PPL, RI Energy will get an Advanced Distribution Management System (ADMS) with Fault Location, Isolation, and Service Restoration (FLISR) functionality. The timeline for this functionality is tied to the transition of IT systems from National Grid which is targetted to occur in calendar year 2024. Each mainline recloser will be installed with a radio as described in the response to Division 3-23. There are no additional costs or timelines.

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Rhode Island Energy™
a PPL company

December 8, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 4</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Division of Public Utilities and Carriers' Fourth Set of Data Requests in the above-referenced matter.

The Company received an extension to December 15, 2025 to respond to Division 4-38.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

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Rhode Island Energy™
a PPL company

December 15, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Response to Division 4-38

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's response to Division 4-38.

This transmittal completes the Company's responses to the Division's Fourth Set of Data Requests in the above-referenced matter.

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

Sincerely,

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cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

Division 4-1
CEMI-4, ERR and Distribution Automation – Various

Request:

RIE acknowledges that it has been meeting its state regulatory reliability performance (page 122) yet is proposing three separate programs (total spend over $100M) with the objective to target select feeders for reliability improvement. Please explain what the Company believes is the need for the distribution automation program, CEMI-4 and ERR considering regulatory reliability performance is currently being met. Please include in the response, why the investments are needed now and planned over the next five to seven years.

Response:

The needs for the approximately $17.2 million included in the FY 2025 ISR Plan proposal for the distribution automation program, CEMI-4 and ERR programs are summarized in Section 3.0 of the Distribution Automation Recloser Program (pages 122-124), Sections 2 and 3 of the CEMI-4 Program (pages 139-141) and Sections 2 and 3 of the ERR Program (pages 152-153).

Generally, the need for these investments is to address areas of the system that are above system regulatory reliability thresholds. Specifically, the FY 2025 Distribution Automation Recloser investments target circuits with frequencies greater than 1.5 as compared to the system regulatory frequency of 1.05; the CEMI-4 program targets customers with frequencies of 4 or greater as compared to the system regulatory frequency of 1.05; and the ERR program targets circuits with high frequency and/or duration as compared to system regulatory values.

The investments are needed now because the issues exist now. The future year investments would be needed as described by the timing and cash flows described within the relevant program documents. For the Distribution Automation Recloser Program, see Figures 11, 12, and 13 (pages 131 and 132). For the CEMI-4 Program, see Sections 4.1 and 4.2 and Table 9 (pages 11-145, and 148). For the ERR Program, see Section 3 (page 153).

Division 4-2

CEMI-4, ERR and Distribution Automation – Various

Request:

Does the Company's proposal to implement three independent programs (CEMI-4, ERR and FLISR) that rely on varying methods to rank and address feeder performance, and further that must be correlated to avoid overlap, meet the objectives of a systematic approach and cost-effective strategy. If so, please explain.

Response:

Yes, the three reliability programs independently represent cost-effective strategies and together represent a systematic approach and overall cost-effective strategy. Each program stands on its own need and recommendations and covers three different important reliability topics: circuits with poor reliability performance, customers with poor reliability performance hidden by system metrics, and distribution automation. The three topics form a systematic approach. Correlation between programs and projects is a common practice to create an overall cost-effective system.

The CEMI-4 and Distribution Automation programs are designed to address immediate needs and have a sunset of 5 to 10 years. After the sunset period, the Company expects to continue the ERR program, which will incorporate distribution automation as needed based on changing system configurations targeting and CEMI-4 considerations as needed.

Division 4-3

CEMI-4, ERR and Distribution Automation – Various

Request:

In Docket 3628 RIE provides a quarterly report of the worst performing 25 circuits (5%) and outage causes and reliability statistics. How does RIE use this report to select feeder reliability improvement projects in the CEMI-4 program and in the ERR program?

Response:

RIE does not use the quarterly report of the worst performing 25 circuits (5%) to select feeder reliability improvement projects in the CEMI-4 program and in the ERR program. Each quarter RIE files a report of the worst 5% preforming frequency circuits for the previous quarter. The report includes the number of customers served, towns impacted, number of events the average duration, the total customer minutes interrupted, the event cause, and the corrective action. All the data on the report comes from the IDS event details compiled on the outage record at the time of the event. The data sets used to select reliability improvement projects for the CEMI are shown in Attachment DIV 3-22-2. This data is pulled from the same event record database as the quarterly report, however the CEMI-4 and ERR programs use more data than a specific quarter report. For CEMI, additional outage attributes are included such as: failed component, the full event text, and the open device type.

The difference between the two data sets is that CEMI-4 and ERR program use multiple years of event history while the quarterly report is restricted to performance for the prior 3 months. Further, the quarterly report data which lists the worst 5 % of the quarter is based on the highest number of customers interrupted. It does not capture the rolling 12 month high CEMI customer counts the program is designed to address. Also see the response to Division 3-22 part m.

Division 4-4

CEMI-4, ERR and Distribution Automation – Various

Request:

Explain how a feeder on the list of 25 worst performing feeders would be classified in the CEMI-4 program versus the ERR program.

Response:

The programs are prioritized on an annual basis, roughly in parallel. If a circuit is included in the CEMI-4 program, it is removed from the ERR program. The ERR program would then select the next feeder on its priority list.

Prepared by or under the supervision of: Ryan Constable

Division 4-5

CEMI-4, ERR and Distribution Automation – Various

Request:

Compare and contrast the ERR program to the worst performing feeder work reported in Docket 3628. Are targeted circuits selected using the same reliability metrics? Are solutions developed and recommended projects determined in the same manner? Will ERR result in similar levels of work, or if not, why?

Response:

Solutions derived from responding to circuits on Docket 3628 quarterly report are typically restricted to action required to bringing the interrupted circuit back to a minimum safety and reliability performance. Typically, the corrective actions are completed by field personnel at the time service is restored. Prior reliability performance is not analyzed at the time of repair.

In comparison, solutions recommended as part of the ERR program are not developed in the same manner. An area Field Engineer will review the frequency and duration performance from the previous 5 years to find event trends and recommend solutions.

As explained in Division 4-4, targeted circuits are selected by using five-years of frequency and duration circuit performance. Quarterly performance reports produced as required by Docket 3628 target circuits with the worst frequency performance for the previous quarter.

A small portion of the ERR program recommendations (such as; placement of animal guards, spot tree trimming, and replacement of surge arrestor, etc.) are similar to work done to restore power (e.g. are like what is listed on the quarterly report). The remaining recommendations (such as reconductoring or adding sectionalization) represent larger efforts with high costs and longer construction horizons. These solutions need to be designed, scheduled, and funded within the ISR framework.

Division 4-6
CEMI-4, ERR and Distribution Automation – Various

Request:

For the Feeder Ranking Reports under Docket 3628, provide (by year for the previous five years):

a. A list of feeders that received corrective actions. Include calculated CKAIDI/CKAIFI used at the time of selection
b. Total number of individual corrective action projects
c. Total spend
d. ISR Plan category for expenditures
e. Number /type of recloser installed as a corrective action and associated cost

Response:

a. The Feeder Ranking Reports under Docket 3628 are developed for regulatory reporting and are not used to identify long term corrective actions. As it has been stated in Division 3-22, the actions taken to immediately restore interrupted customers are noted on the outage comments. In most cases, a single repair is made to restore power at the time of the outage. The Company uses programs such as ERR and CEMI to identify circuits with reliability concerns that warrant long term corrective actions. Circuit SAIDI (CKAIDI) and Circuit SAIFI (CKAIFI) used at the time of selection of 25% of worst performing feeders in that quarter is included in the quarterly report.

b. See response a.

c. See response a. Immediate corrective actions of ad hoc repairs are not tracked on a per job basis.

d. See response a. Immediate corrective actions of ad hoc repairs typically fall under damage and failure.

e. A review of Docket 3628 quarterly reports between 2018 and 2022 found one instance of a recloser installation as an immediate corrective action. This was reported in 2nd Quarter 2021 and consisted of replacing a failed pole top recloser on the 85T1. As stated in b. ad hoc repairs are not tracked on a per job basis. The recloser was replaced with a G&W Viper S with a 651R control.

Division 4-7
CEMI-4, ERR and Distribution Automation – Various

Request:

Does RIE believe the "Cause" listed in the table of the Quarterly Feeder Ranking Reports (under Docket 3628) represents a root cause analysis?

Response:

No, RIE does not consider the "Cause" listed in the table of the Quarterly Feeder Ranking Reports (under Docket 3628) to represent a root cause analysis. This field represents the cause of that specific outages which occurred in the three month period of the quarter being reported.

As the Company explained in the response to Division 3-22, part u, a root cause analysis per outage is not performed. During reliability reviews, the engineer gathers all the outages and their causes for a longer period of time and then evaluates the most appropriate solution for the grouped outages.

Prepared by or under the supervision of: Ryan Constable

Division 4-8
CEMI-4, ERR and Distribution Automation – Various

Request:

Provide a detailed explanation of each difference between the CEMI-4 program and the ERR program.

Response:

The ERR program is designed to improve circuit reliability of the worst preforming circuits in RIEs distribution network. As noted in Divisoin 4-5, circuit selections are made by considering 5 years' worth of circuit frequency (CKAIFI) and durations (CKAIDI). Work recommended by this program is designed to improve reliability to bring statistical performance closer to the system average. Work is often concentrated on the main line sections of this circuit because it has the greatest statistical impact on the circuit. This is the traditional method of employing capital investment dollars to optimize reliability improvement.

While using average system and circuit reliability statistics are common for benchmarking performance and system planning, using them exclusively can drive investment decisions to parts of the system that have the highest customer densities. This can lead to uneven reliability performance in areas that do not have the customer counts to statistically influence system averages. As a result, reliability performance for individual customers can seriously degrade with no mechanism for improvement.

The CEMI program is a reliability program designed to specifically improve reliability for RIE's customers that are experiencing significantly more interruptions then the average customer.

The data set for the CEMI program starts with the customers who have experienced a high number of interruptions. See DIV 3-22-2 for a sample of customers experiencing between 7 to 10 interruptions within a rolling 12-month period. The reliability statistics of the circuit that serves these customers is not relevant for inclusion in the program.

From a reliability solution perspective, working from the customer address back to the circuit's source provides a unique look at all the outage events driving the high CEMI customer counts. This expanded view leads to an examination of the circuit topology, line construction, and line exposure considerations that may be missed under a more traditional reliability program because they are statistically irrelevant. A number of solutions include reducing exposure by balancing the number of customers served from adjacent single phase taps, adding sectionalizing line cutouts, installing cutout mounted reclosers that have the ability to clear temporary faults, and adding line reclosers to pick up healthy line sections that would otherwise remain out of service

CEMI-4, ERR and Distribution Automation – Various

for an upstream outage. See DIV 3-21-2 for a list of proposed improvement projects specified under the CEMI program for FY 2025.

While the above solutions can be effectively used under both programs, the objectives of the two programs are different. The goal of the ERR's program is to bring the circuit performance closer to the system averages, while the CEMI program is designed to make recommendations that specifically address reliability problems at the customer level.

Division 4-9
CEMI-4, ERR and Distribution Automation – Various

Request:

For the ERR program, the Company states that (page 153):

"Once the feeders are selected, Field Engineers, working closely with Operations Supervisors, will review circuit reliability and event history looking for locations of frequent outages caused by vegetation issues, animal contact, and equipment failures. Field inspections will also include infrared surveys, system pole line construction reviews, line balancing opportunities, system hardening locations, protection coordination concerns, and reviewing locations for additional sectionalizing."

a. Does the CEMI-4 program use this same approach to solutions development, including field inspections? If not, why?

b. Does the Company consider the same options to resolve reliability issues in both the CEMI-4 and ERR programs? If not explain.

c. Are options prioritized differently between the programs? If so, explain.

d. Are solutions compared to alternatives to validate the most cost-effective remedy in each program? If not, why?

Response:

a. The CEMI program does include field inspections. As described in Division 4-8, the CEMI-4 program and the ERR program approaches are different. The CEMI-4 program finds solutions for specific customer addresses on a circuit regardless of the line section's statistical impact on circuit frequency. Solution development starts at the customer and works back toward the circuit source.

   The ERR program's goal is to improve the circuit's frequency and duration performance closer to system averages. This leads to the traditional investment strategy of considering improvements to the most statistically important sections of the circuit. This typically directs spending to the circuit main line sections.

b. The Company does consider similar options to resolve issues. However, some solutions, (such as, balancing the customer counts on adjacent single phase taps or adding a signal phase line cutouts to reduce the exposure to customer beyond a troublesome line section) are not typically done when the goal is to improve circuit based reliability.

Division 4-9, page 2

CEMI-4, ERR and Distribution Automation – Various

c. The options are prioritized differently as noted in section b. Solutions are prioritized based on the goals of the program. CEMI recommends more projects that influence customer interruptions, while ERR remedies are designed to statistically improve circuit performance. Work tends to be concentrated on mainline sections of the circuit because outages there have a greater statistical impact. See Division 4-8 for details.

d. As a practice, the cost of the Company's chosen solutions are always compared to alternatives. This is done at all stages of the process, from the initial design chosen by the engineer, to the standardized equipment the Company purchases in bulk. Each decision is made to employ the most economical solution. The resources put into the alternative analysis are determined by the cost of the solution. Since many solutions in both programs cost under $100,000 to build, standardized unit costs are used for planning consideration. See Bates 149 Appendix A, 6 Sample Proposed work list and Estimated Costs. The most economic solutions are often pursued at the start of the initiative, rather than conducting a more robust alternatives solutions done in a classic planning study that recommend solutions with significantly higher costs.

Division 4-10
CEMI-4, ERR and Distribution Automation – Various

Request:

For ERR, is the Company using outage data based on the Rhode Island PUC definition of sustained interruption (loss of electric power lasting equal to or more than one minute) or the IEEE definition (loss of electric power lasting five or more minutes) to select circuits? Will the Company measure and report results using the same methodology? If not the same, why?

Response:

The Company used outage data based on the Rhode Island PUC definition of sustained interruption to select ERR circuits for the program's first year because it matched the Company's legacy software. When reporting program results, outage statistics pre and post program will initially be consistent with the RIPUC definition of sustained interruption and noted within the results.

The Company does intend to transition the ERR program to an IEEE definition with a loss of power lasting five or more minutes as described in the response to FY 2024 Division 2-4 and FY 2025 Division 3-4.

Prepared by or under the supervision of: Ryan Constable

Division 4-11
CEMI-4, ERR and Distribution Automation – Various

Request:

The Company reviews annual performance to rank circuits, completes the ERR circuit list by October 1st each year, recommends projects by December 31st and completes designs by April 1st (page 153). If circuit selection is based on annual performance, why is the program finalized nearly 15 months after year end?

Response:

To have projects ready for construction at the beginning of the fiscal year in April, time is needed to create the ERR circuit list, identify each project, complete the engineering, design the upgrades, and acquire the necessary materials.

To create the circuit ranking for this program, five years of reliability performance data is compiled at the beginning of September. This provides time for review by Field Engineering, Operations, and the System Control Center to select the circuits for the ERR program.

Field Engineering begins their assessments in October to have engineered plans to the Design group for January 1st. Design pulls together the construction documents for each project to make sure each job is shovel-ready for April 1st.

It's expected to take the Company seven months from the start of data gathering to when the Company implements the first project. The aim is to have as many reliability upgrades constructed in the first half of the fiscal year.

Prepared by or under the supervision of: Ryan Constable and Eric Wiesner

Division 4-12
CEMI-4, ERR and Distribution Automation – Various

Request:

In executable format, provide all analysis relied upon to identify the FY 2024 and FY 2025 ERR circuit lists.

Response:

The Company reviews annual performance and creates a ranked worst performing circuit list based on five years of reliability data. Details related to the creation of the list can be found in the response to Division 2-1.

The ERR circuit selections are based on the 5% worst ranked circuits excluding feeders that have been part of the CEMI or ERR program in the past three years. Engineering works collaboratively with Operations and the Electric Control Center to review the list. Circuits may be removed or added to the list based on recent performance issues or significant construction occurring on the feeder.

Attachment DIV 4-12 ERR 2025 Circuit List Selection spreadsheet is the document that was used to finalize the feeders for the program. The worst performing data for all circuits can be found on the Master List tab. Information related to past reliability program participation was added. Also, SAIFI and SAIDI screens were added to show which circuits were underperforming.

Circuit selection was reviewed with the control center and the Coastal and Capital Regions operations personnel. The details can be seen on the Review with Operations tab. One circuit was added to the list based on a few recent large events. A few other circuits requested by operations were already actively under review or the performance was not very poor.

The ERR List 10-2-23 tab represents the final list for the 2025 ERR program. The total customer count for these 17 circuits is just over 6% of the total system customers.

Attachment DIV 4-12

The Company provided the Excel version of Attachment DIV 4-12.

Division 4-13

CEMI-4, ERR and Distribution Automation – Various

Request:

Provide a list of each circuit proposed for work under the worst performing circuit program in FY 2024. For each circuit, provide information comparable to pp. 155-159.

Response:

Attachment DIV 4-13 contains the reports for the FY 2024 worst performing circuits.

Prepared by or under the supervision of: Ryan Constable

Rhode Island Energy™
a PPL company

Memorandum

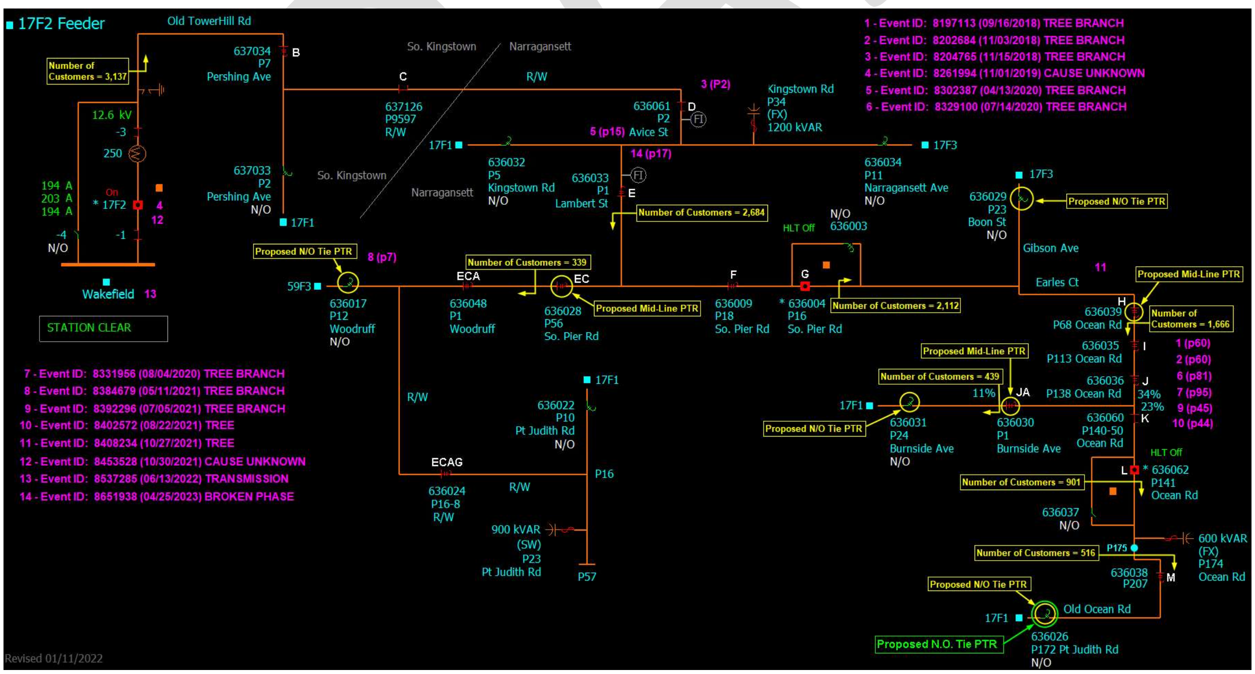
To: Eric Wiesner

From: Frank Louis Carro

Date: 10/24/2023

Subject: Problem and Poor Performing Reliability Review for feeder 17F2

This memo documents the recommendations to improve CKAIDI and CKAIFI on the 2022 Poor Performing **17F2** feeder.



PRESENT CONFIGURATION OF 17F2

- Supplied at 34.5kV.
- Three transformers three feeder substation.
- Total circuit feet: 37 miles.
  - One Phase distance: 22 miles.
  - Three Phase distance: 15 miles.
- Total connected load: 23233 kVA.
  - Phase A: 5293 kVA
  - Phase B: 6368 kVA
  - Phase C: 5503 kVA
- Three overhead feeder ties with 17F1, 17F3, and 59F3.
- Total customers: 3137.

RELIABILITY PERFORMANCE3137

This table illustrates the historical reliability performance of the Wakefield 17F2, 12.47 kV feeder for the 5-year period ending in 2022. Predicted reliability improvements will be provided with any recommendations listed in this document.

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
	No	56-17F2	21	2938	Mixed	14.45	21.3	157.0	93.7	10.1	192.6		

							CKAIFI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		56-17F2	21	2938	Mixed	14.45	1.15	2.76	1.19	0.10	2.55		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 and >= 30 min for CKAIDI)

DAY TYPE	Estimated CKAIFI	Estimated CKAIDI Min	Protective Device_GIS_ID	FDR	Feeder _Cs	Year	TIME OFF	UNIQUE LOCATION	CAUSE INTRPTN DESC	Classification	EVENT CI	EVENT CMI
Blue Sky	0.668	38.752	48832346	56-17F2	2938	2018	9/16/2018	56-17F2: G: SOUTH PIER RD (1710)	Tree - Broken Limb	Main line - overhead	1963	113854.00
Blue Sky	0.668	63.905	231524825	56-17F2	2938	2018	11/3/2018	56-17F2: L: OCEAN RD (1320)	Tree - Broken Limb	Main line - overhead	1962	187752.00
Blue Sky	1.000	60.020	35146046	56-17F2	2938	2018	11/15/2018	56-17F2: A: HL 3307 LI HGLN (1154)	Tree - Broken Limb	Main line - overhead	2939	176340.00
Major Storm	0.994	542.926	277211541	56-17F2	2938	2019	11/1/2019	56-17F2: I: OCEAN RD (1320)	Unknown	Main line - overhead	2921	1595116.00
Major Storm	0.993	107.191	35146046	56-17F2	2938	2020	4/13/2020	56-17F2: A: HL 3307 LI HGLN (1154)	Tree - Broken Limb	Main line - overhead	2916	314928.00
Blue Sky	0.991	63.799	35146046	56-17F2	2938	2020	7/14/2020	56-17F2: A: HL 3307 LI HGLN (1154)	Lightning	Main line - overhead	2912	187440.00
Major Storm	0.666	165.859	48832346	56-17F2	2938	2020	8/4/2020	56-17F2: G: SOUTH PIER RD (1710)	Tree - Broken Limb	Main line - overhead	1957	487293.00
Blue Sky	1.004	41.736	35146046	56-17F2	2938	2021	5/11/2021	56-17F2: A: HL 3307 LI HGLN (1154)	Tree - Broken Limb	Main line - overhead	2951	122620.00
Blue Sky	0.665	60.010	231524825	56-17F2	2938	2021	7/5/2021	56-17F2: L: OCEAN RD (1320)	Tree - Broken Limb	Main line - overhead	1954	176310.00
Major Storm	0.003	6.031	278170053	56-17F2	2938	2021	8/22/2021	56-17F2: D: KINGSTOWN RD (1020)	Tree Fell	Main line - overhead	10	17720.00
Major Storm	0.668	633.861	934100046	56-17F2	2938	2021	8/22/2021	56-17F2: LIA: KNOWLESWAY (8004)	Tree Fell	Main line - overhead	1963	1862284.00
Major Storm	0.669	564.073	231524825	56-17F2	2938	2021	10/27/2021	56-17F2: L: OCEAN RD (1320)	Tree Fell	Main line - overhead	1966	1657246.00
Blue Sky	1.321	53.452	564035088	56-17F2	2938	2021	10/30/2021	56-17F2: C: HL 3302 HGLN (8002)	Unknown	Main line - overhead	3880	157043.00
Blue Sky	2.590	7.771	35146046	56-17F2	2938	2022	6/13/2022	56-17F2: A: HL 3307 LI HGLN (1154)	Lightning	T or D Supply - above 69 KV	7610	22830.00
Blue Sky	1.000	76.492	277191764	56-17F2	2938	2023	4/25/2023	56-17F2: E: LAMBERT ST (1055)	Device Failed	Main line - overhead	2937	224733.00

Reliability of the Wakefield 17F2 feeder primarily influenced by tree-related outages.

COMPLETED WORK

Feeder Numbe	WR Number	WR Status Cod	Work Request Description	Job Type Code
56-17F2	8667911	90	NEED TO REPLACE PADMOUNT TRANSFOMER 75 KVA 120/208 7200 FEED OFF P.146 OCEAN DRI	DRELIABLE
56-17F2	3050574	90	Install Fault Indicators	DRELIABLE
56-17F2	6121604	90	P.141 OCEAN RD NARRAGANSETT FY11 GAP RECLOSER PROJECT dm	DRELIABLE
56-17F2	9383376	90	NESRELFY11-telco to install 45'2 , replace L/B -need dig safe doc.	DRELIABLE
56-17F2	9419342	90	TELCO to repl 2 poles. Inst xfmr and repl OW secondary	DRELIABLE
56-17F2	9421775	90	NESRELFY11- @P18 NEED TO TRANSFER EQUIPMENT AFTER TELCO SET POLE	DRELIABLE
56-17F2	9422379	90	NESRELFY11- REPLACE CROSSARMS ON P22 dm	DRELIABLE
56-17F2	9427466	90	NESRELFY11- TRANSFER NGRID EQUIPMENT ON P141 AFTER TELCO SET NEW POLE	DRELIABLE
56-17F2	9428351	90	NESRELFY11- NEED TO TRANSFER ALL NGRID EQUIPMENT AFTER TELCO SET POLEdm	DRELIABLE
56-17F2	9428424	90	NESRELFY11- @P 99 NEED TO REPLACE DOUBLE CROSS ARMS do w 9430012	DRELIABLE
56-17F2	9430012	90	NESRELFY11- @P64 NEED TO REPLACE CROSSARM, O CS 9-411 dm w 9428424	DRELIABLE
56-17F2	9776713	90	P 15-2 SOUTH PIER RD - DOUGLAS DR LEANING POLE CHECK TO INSTALL GUY WIRE	DRELIABLE
56-17F2	12375484	90	COF Customer voltage complaint. Replace transformer bank.	DRELIABLE
56-17F2	13896554	90	upgrade XFMR at P8 to 50kva	DRELIABLE
56-17F2	15331834	90	Install 25 kVA xfmr.open crib at P15 Follet Road	DRELIABLE
56-17F2	16367519	90	P 1 SYLVAN RD - TELCO INSTALLED ANCHOR - INSTALL DOWN GUY	DRELIABLE
56-17F2	16800218	90	P2 AVICE ST-INSTALL IN-LINE DISCONNECTS ON 17F2-SWITCH # 636061	DRELIABLE
56-17F2	20317434	90	Replace service with 3C#2Al triplex	DRELIABLE
56-17F2	22076910	90	Recloser radio install, 4 Locations, Wakefield	DRELIABLE
56-17F2	23632739	90	P36 Ocean Rd - remove 25kVA and install (2) 50kVA SS xfmrs OPEX 8.89%	DRELIABLE
56-17F2	25046367	90	Replace recloser P16-3A- OPEX 21.32%	DRELIABLE
56-17F2	16800572	90	P9597 IN THE 3302 ROW-INSTALL IN-LINE DISCONNECTS ON 17F2 (SWITCH # 637126)	DRELIABLE

PENDING WORK

None

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Predicted reliability improvements are included with each recommendation.

<u>Tree Trimming</u>: **Not Recommended**
Trimming was last performed May 2022. Next trimming cycle is FY27.

<u>Infrared Circuit Scan</u>: **Not Recommended**
Infrared scanning is not recommended at this time. Rhode Island Energy is currently assessing an annual infrared program.

<u>Animal Mitigation</u>: **Not Recommended**
Not required.

<u>Fault Indicators</u>: **Not Recommended**
Not required.

Load Balancing: **Not Recommended**
Not required.

Protective Device Coordination Review: **Recommended**
Performed a full coordination review of the 17F2 feeder. Recommendations are being made to change the OC, G, and R settings for the PTR located at Pole 16 South Pier Road, Narragansett, RI. Recommendations are also being made to change the OC and G settings for the PTR located at Pole 141 Ocean Road, Narragansett, RI.

Cutout Mounted Recloser (CMR) Installations:
No CMRs are recommended at this time. **Not Recommended**

Line Recloser Installations: **Not Recommended**
No PTRs are recommended at this time.

Additional Circuit Sectionalizing: **Recommended**
Replace the N.O. Tie loadbreak switch with a new N.O. G&W, 15 kV PTR with SEL-651R2 controls at Pole 172 Point Judith Road, Narragansett, RI. The N.O. Tie PTR would be operated via SCADA to immediately pick up the 901 customers located between the PTR at Pole 141 Ocean Road, Narragansett, RI, and the new N.O. Tie PTR located at Pole 172 Point Judith Road, Narragansett, RI.
Note: Based upon 5-year average reliability numbers, installation of this PTR would have saved an average of 2,162 customers interrupted (CI) and 558,260 customer minutes interrupted (CMI) per year on the Wakefield 17F2 feeder.

Additional Feeder Ties/Reconfiguration: **Not Recommended**
No additional feeder ties or reconfigurations are recommended at this time.

Other Recommendations: **Recommended**
Replace the 150E, SM-4 station transformer high-side fuses with 200 E, SM-4 fuses. The 150E fuses are presently the summer normal (SN) limiting element for the Wakefield 17F2 feeder with a SN Rating of 10.02 MVA (464 Amps). Summer 2024 peak load of the 17F2 feeder is projected to be 11.04 MVA (511 Amps) which is 110 % of its SN Rating. The 200E, SM-4 fuses have a SN Rating of 13.43 MVA (622 A). The new SN Limit of the 17F2 feeder would become the 336 Al Bare Conductor which has a SN Rating of 11.12 MVA (515 Amps).

Short Term Recommendation – Estimated Cost Summary

Funding Project Number	STORMS Code	Title/Description	Capital ($)	O&M ($)	Removal ($)	Total ($)
	ERR2023RI	Replace the N.O. Tie loadbreak switch with N.O. PTR at Pole 172 Point Judith Road, Narragansett, RI.	$80,000	$1,000	$2,000	$83,000
COS0025	ERR2023RI	Replace 150E, SM-4 station transformer high-side fuses with 200E, SM-4 fuses.	$5,000	$3,000	$2,000	$10,000

LONG TERM SYSTEM IMPROVEMENTS (SOUTH COUNTY AREA STUDY)

Re-route front end of 17F2 feeder with 477 Al bare conductor from the R.O.W. onto Narragansett Avenue:
Install 4,600 feet (0.87 miles) of 477 Al bare conductor from Pole 4 Old Tower Hill Road to Narragansett Avenue, Schoolhouse Road, and Avice Street in Narragansett, RI. Note: the 17F2 feeder will be double circuited with the 17F3 feeder along the route. Re-conductor 1,100 feet (0.21 miles) of 336 Al bare conductor and 500 feet (0.09 miles) of 4/0 Cu bare conductor with 1,600 feet (0.30 miles) of 477 Al bare conductor from Pole 9588 R.O.W. (off Schoolhouse Road, Narragansett, RI) to Pole 15 Kingstown Road, Narragansett, RI. Install one (1) advanced capacitor bank. Design work is tentatively scheduled to commence in FY2025. Install new 17F1/17F2 N.O. Tie loadbreak switch. Install two (2) new advanced capacitor banks. Design work is tentatively scheduled to commence in FY2025.

Perform 17F2 Distribution Substation Upgrades:
Replace the 4/0 Al bare bus conductor on the 17F2 feeder with 477 Al bare bus conductor to match the 17F1 and 17F3 feeder bays. Replace the 89-F2 (4T34) 600 Amp airbreak switch and 150 E SM-4 transformer high-side fuses with a 1,200 Amp circuit switcher to match the 17F1 and 17F3 feeder bays. Design work is tentatively scheduled to commence in FY2025.

Long Term Recommendation – Estimated Cost Summary

Funding Project Number	STORMS WR No.	Title/Description	Capital ($)	O&M ($)	Removal ($)	Total ($)
	South County Study	Re-route front end of 17F2 feeder with 477 Al bare conductor from the R.O.W. onto Narragansett Avenue.	$1,428,200	$132,500	$137,200	$1,697,900
	South County Study	Perform 17F2 Distribution Substation Upgrades.	$832,000	$0	$26,000	$858,000

CONSIDERATIONS FOR ACTIVE/PENDING STUDIES

Project Description:
There are no active/pending studies affecting this feeder.

Rhode Island Energy™
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Memorandum

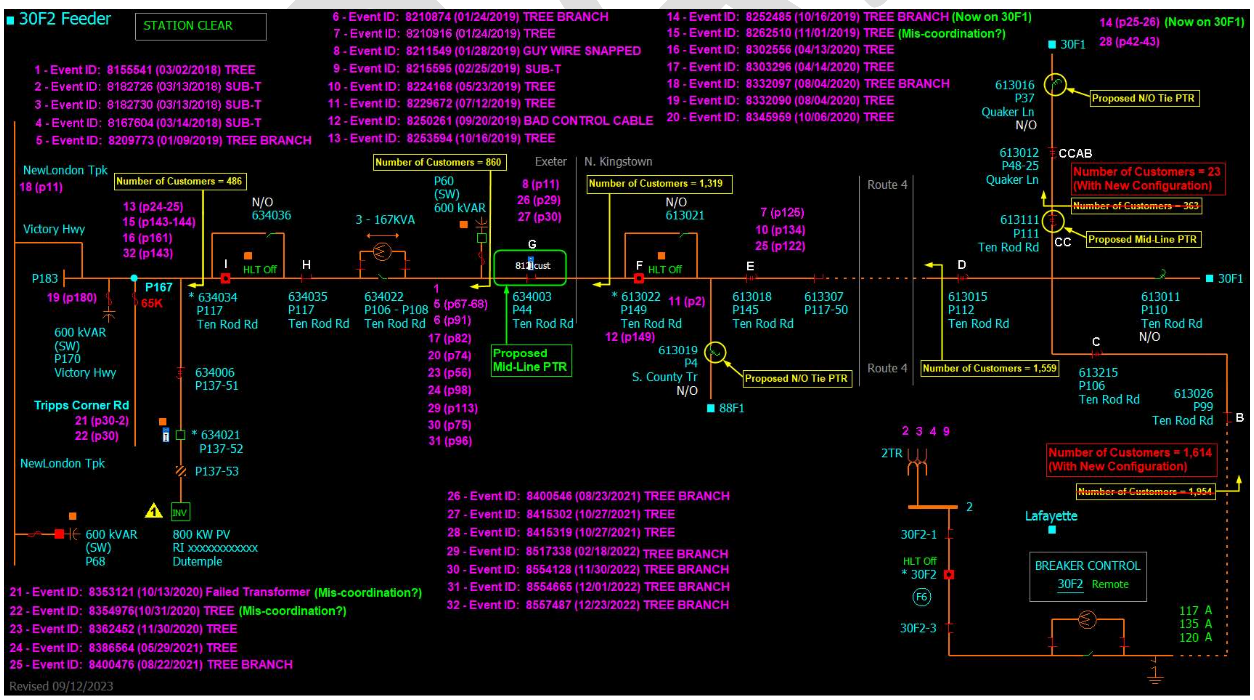
To: Eric Wiesner

From: Frank Louis Carro

Date: 10/24/2023

Subject: Problem and Poor Performing Reliability Review for Feeder 30F2

This memo documents the recommendations to improve CKAIDI and CKAIFI on the 2022 Poor Performing **30F2** feeder.



PRESENT CONFIGURATION OF 30F2

- Supplied at 34.5kV.
- Two transformers two feeder substation.
- Total circuit feet: 75 miles.
    - One Phase distance: 51 miles.
    - Three Phase distance: 14 miles.
- Total connected load: 185978 kVA.
    - Phase A: 4170 kVA
    - Phase B: 5073 kVA
    - Phase C: 4900 kVA
    - 3-Phase: 4445
- Three overhead feeder ties with 30F1 and 88F1.
- Total customers: 1614.

Approximately 1.5 MVA (68 A) of load and 340 customers were transferred from the 30F2 feeder to the 30F1 feeder. Switching was performed in 2023 to relieve capacity on the 30F2 feeder and allow for the interconnection of a new customer with a projected load of 2.4 MVA (110 A).

RELIABILITY PERFORMANCE

This table illustrates the historical reliability performance of the Lafayette 30F2, 12.47 kV feeder for the 5-year period ending in 2022. Predicted reliability improvements will be provided with any recommendations listed in this document.

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
	No	56-30F2	8	1869	Mixed	15.50	224.2	283.2	255.7	546.4	75.6		

							CKAIFI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		56-30F2	8	1869	Mixed	15.50	2.84	1.76	3.20	6.30	1.57		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 and >= 30 min for CKAIDI)

DAY_TYPE	Estimated CKAIFI	Estimated CKAIDI Min	Protective Device_GIS_ID	FDR	Feeder _Cs	Year	TIME_OFF	UNIQUE_LOCATION	CAUSE_INTRPTN_DESC	Classification	EVENT_CI	EVENT_CMI
Major Storm	0.597	2106.035	277460507	56-30F2	1869	2018	3/2/2018	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1115	3936180.00
Major Storm	1.617	255.213	277335817	56-30F2	1869	2018	3/13/2018	56-30F2: DAA: PLAIN RD (1449)	Tree Fell	T or D Supply - below 69 KV	3022	476993.00
Major Storm	1.514	667.961	75414050	56-30F2	1869	2018	3/13/2018	56-30F2: I: TEN ROD RD (0577)	Unknown	T or D Supply - below 69 KV	2830	1248420.00
Blue Sky	1.705	10.231	34698393	56-30F2	1869	2018	3/14/2018	56-30F2: A: HL 3302 HGLN (1855)	Other Company Activities	T or D Supply - below 69 KV	3187	19122.00
Blue Sky	0.664	21.912	277460507	56-30F2	1869	2019	1/9/2019	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1241	40953.00
Blue Sky	0.664	47.143	277460507	56-30F2	1869	2019	1/24/2019	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1241	88111.00
Blue Sky	1.270	117.596	277300013	56-30F2	1869	2019	1/24/2019	56-30F2: ITA: TEN ROD RD (0155)	Tree Fell	Main line - overhead	2373	219786.00
Blue Sky	0.664	43.823	277460507	56-30F2	1869	2019	1/28/2019	56-30F2: F: TEN ROD RD (1855)	Vehicle	Main line - overhead	1241	81906.00
Major Storm	1.048	144.802	34698393	56-30F2	1869	2019	2/25/2019	56-30F2: A: HL 3302 HGLN (1855)	Deterioration	T or D Supply - below 69 KV	1959	270635.00
Blue Sky	0.987	57.381	277190294	56-30F2	1869	2019	5/23/2019	56-30F2: E: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1844	107246.00
Blue Sky	0.987	160.730	277190294	56-30F2	1869	2019	7/12/2019	56-30F2: E: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1845	300405.00
Blue Sky	0.666	62.441	277460507	56-30F2	1869	2019	9/20/2019	56-30F2: F: TEN ROD RD (1855)	Device Failed	Main line - overhead	1244	116702.00
Major Storm	0.225	347.865	75414050	56-30F2	1869	2019	10/16/2019	56-30F2: I: TEN ROD RD (0577)	Tree Fell	Main line - overhead	420	650160.00
Major Storm	0.810	829.948	277300517	56-30F2	1869	2019	10/16/2019	56-30F2: GQF: WILLIAM REYNOLDS RD (0210)	Tree - Broken Limb	Main line - overhead	1513	1551172.00
Major Storm	0.624	563.247	277460507	56-30F2	1869	2019	11/1/2019	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1166	1052708.00
Major Storm	0.248	158.142	75414050	56-30F2	1869	2020	4/13/2020	56-30F2: I: TEN ROD RD (0577)	Tree Fell	Main line - overhead	464	295568.00
Blue Sky	0.577	29.993	277460507	56-30F2	1869	2020	4/14/2020	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1078	56056.00
Major Storm	0.247	313.714	278023868	56-30F2	1869	2020	8/4/2020	56-30F2: L: HOG HOUSE HILL RD (0100)	Tree - Broken Limb	Main line - overhead	462	586332.00
Major Storm	0.419	365.246	277460507	56-30F2	1869	2020	8/4/2020	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	783	682645.00
Blue Sky	0.668	16.026	277460507	56-30F2	1869	2020	10/6/2020	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1248	29952.00
Blue Sky	0.248	11.486	75414050	56-30F2	1869	2020	10/13/2020	56-30F2: I: TEN ROD RD (0577)	Device Failed	Main line - overhead	463	21468.00
Blue Sky	0.247	12.219	75414050	56-30F2	1869	2020	10/31/2020	56-30F2: I: TEN ROD RD (0577)	Tree Fell	Main line - overhead	462	22838.00
Major Storm	0.668	222.356	277460507	56-30F2	1869	2020	11/30/2020	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1248	415584.00
Blue Sky	0.897	135.488	277460507	56-30F2	1869	2021	5/29/2021	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1677	253227.00
Major Storm	0.996	2112.057	75414050	56-30F2	1869	2021	8/22/2021	56-30F2: I: TEN ROD RD (0577)	Tree - Broken Limb	Main line - overhead	1862	3947435.00
Blue Sky	0.245	44.013	277460507	56-30F2	1869	2021	8/23/2021	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	457	82260.00
Major Storm	0.670	1045.411	277460507	56-30F2	1869	2021	10/27/2021	56-30F2: F: TEN ROD RD (1855)	Tree Fell	Main line - overhead	1253	1953873.00
Major Storm	0.326	105.016	277190644	56-30F2	1869	2021	10/27/2021	56-30F2: CCAB: QUAKER LN (1520)	Tree Fell	Main line - overhead	610	196274.00
Blue Sky	0.671	71.791	277460507	56-30F2	1869	2022	2/18/2022	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1254	134178.00
Blue Sky	0.673	23.539	277460507	56-30F2	1869	2022	11/30/2022	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1257	43995.00
Blue Sky	0.910	58.773	277460507	56-30F2	1869	2022	12/1/2022	56-30F2: F: TEN ROD RD (1855)	Tree - Broken Limb	Main line - overhead	1700	109846.00
Major Storm	0.249	12.440	75414050	56-30F2	1869	2022	12/23/2022	56-30F2: I: TEN ROD RD (0577)	Tree - Broken Limb	Main line - overhead	465	23250.00

Reliability of the Lafayette 30F2 feeder was significantly influenced by tree-related outages events; the majority of which occurred along Ten Rod Road in Exeter, RI.

COMPLETED WORK

Feeder Numbe	WR Number	WR Status Cod	Work Request Description	Job Type Code
56-30F2	1829139	90	Distribution Electric Reliability DM	DRELIABLE
56-30F2	18504964	90	P 17, 17-2 & 17-4 REPLACE TREE GUY WITH ANCHOR & DOWN GUY	DRELIABLE
56-30F2	22048456	90	RECLOSER RADIO INSTALL, 1 LOCATIONS, LAFAYETTE	DRELIABLE
56-30F2	22295531	90	RECLOSER RADIO INSTALL, 3 LOCATIONS, LAFAYETTE	DRELIABLE
56-30F2	24319160	90	210 TRIPPS CORNER RD-INSTALL ANCHORS REMOVE TREE GUYS FOR TREE-OPEX 1.24%	DRELIABLE
56-30F2	26468309	90	70 NEW RD-P 26-2 -REMOVE TREE GUY ..INSTALL ANCHOR DOWN GUY..NG TO TRIM-OPEX 2.1	DRELIABLE
56-30F2	27044167	90	CHANGE SINGLE PHASE TAPS AT 3 LOCATIONS, REPLACE 1 25K FUSE SEE COMMENTS-OPEX 0%	DRELIABLE
56-30F2	30331919	90	P 69 TEN ROD RD - REPLACE/REFUSE CUTOUTS - COVID PEAK LOAD ANALYSIS	DRELIABLE
56-30F2	30648665	90	Install regulator - Distribution Electric Reliability	DRELIABLE
56-30F2	12237270	90	Distribution Electric Reliability	DRELIABLE
56-30F2	12107560	90	30F2 Remove wire and equip from P191 to P191-7, abandon poles telco remove	DRELIABLE
56-30F2	12867911	90	30F2 Install conduit, cable and transformers at Stonegate URD dm	DRELIABLE
56-30F2	14448651	90	Verizon to replace P.2 & P.3 Arnold Ave - raise secondary, replace PTP guy	DRELIABLE
56-30F2	16891925	90	C046352 - P1 Oakdale, P9282 ROW, P15 Main, P73 Tower Hill tap changes. W	DRELIABLE
56-30F2	16891974	90	C046352 - P24 Oak Hill Rd. Replace Capacitor Controls North Kingstown RI	DRELIABLE
56-30F2	16937073	90	C046352 - P194 Post Rd. Install LVM North Kingstown RI	DRELIABLE
56-30F2	18706692	90	Request Verizon Replace pole 8-1 Scrabbletown	DRELIABLE
56-30F2	27044083	90	TRANSFER A-PHASE TAP TO C-PHASE TAP DOWN HENRY BROWN RD WG RI-OPEX 0%	DRELIABLE

PENDING WORK

None

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Predicted reliability improvements are included with each recommendation.

Tree Trimming: **Not Recommended**
Ten Rod Road was patrolled, and hazard trimmed, several times in 2023. Trimming was last performed in Spring 2021. Next trimming cycle is FY25.

Infrared Circuit Scan: **Not Recommended**
Infrared scanning is not recommended at this time. Rhode Island Energy is currently assessing an annual infrared program.

Animal Mitigation: **Not Recommended**
Not required.

Fault Indicators: **Not Recommended**
Not required.

Load Balancing: **Not Recommended**
Not required.

Protective Device Coordination Review: **Recommended**
Performed a full coordination review of the 30F2 feeder. No recommendations are being made at this time.

Cutout Mounted Recloser (CMR) Installations: **Recommended**
Replace the 25 K line fuse with a 40K CMR at Pole 40 Tripps Corner Road, Exeter, RI.
Note: Based upon 5-year average reliability numbers, installation of this CMR would have saved an average of 36 customers interrupted (CI) and 19,637 customer minutes interrupted (CMI) per year on the Lafayette 30F2 feeder.

Replace the 65 K line fuse with a 65K CMR at Pole 116 Ten Rod Road, Exeter, RI.
Note: Based upon 5-year average reliability numbers, installation of this CMR would have saved an average of 32 customers interrupted (CI) and 13,146 customer minutes interrupted (CMI) per year on the Lafayette 30F2 feeder.

Replace the 65 K line fuse with a 65K CMR at Pole 14 Widow Sweets Road, Exeter, RI.
Note: Based upon 5-year average reliability numbers, installation of this CMR would have saved an average of 38 customers interrupted (CI) and 8,721 customer minutes interrupted (CMI) per year on the Lafayette 30F2 feeder.

Line Recloser Installations: **Recommended**

Install a new G&W, 15 kV PTR with SEL-651R2 controls at Pole 44 Ten Rod Road, Exeter, RI.
Note: Based upon 5-year average reliability numbers, installation of this PTR would have saved an average of 826 customers interrupted (CI) and 78,030 customer minutes interrupted (CMI) per year on the Lafayette 30F2 feeder.

Additional Circuit Sectionalizing: **Not Recommended**

No additional Sectionalizing is recommended at this time.

Additional Feeder Ties/Reconfiguration: **Not Recommended**

No additional feeder ties or reconfigurations are recommended at this time.

Other Recommendations: **Not Recommended**

No other recommendations are being made at this time.

Short Term Recommendation – Estimated Cost Summary

Funding Project Number	STORMS WR No.	Title/Description	Capital ($)	O&M ($)	Removal ($)	Total ($)
	ERR2023RI	Remove existing disconnect switches and install a new 30F2 PTR at P44 Ten Rod Road, Exeter, RI	$80,000	$1,000	$2,000	$83,000
	ERR2023RI	Replace existing 25K fuse with new 40K CMR at Pole 40 Tripps Corner Road, Exeter, RI.	$3,000	$1,000	$1,000	$5,000
	ERR2023RI	Replace existing 65K fuse with new 65K CMR at Pole 116 Ten Rod Road, Exeter, RI.	$3,000	$1,000	$1,000	$5,000
	ERR2023RI	Replace existing 65K fuse with new 65K CMR at Pole 14 Widow Sweets Road, Exeter, RI.	$3,000	$1,000	$1,000	$5,000

LONG TERM SYSTEM IMPROVEMENTS (SOUTH COUNTY AREA STUDY)

Re-conductor 30F2 from Pole 121 Ten Rod Road, North Kingstown, RI to Pole 44 Ten Rod Road, Exeter, RI:
Re-conductor 3,600 feet (0.68 miles) of 4/0 Al bare conductor and 6,300 feet (1.19 miles) of 1/0 Al bare conductor with 9,900 feet (1.87 miles) of 477 Al spacer cable. Install one (1) advanced capacitor bank. Design work is tentatively scheduled to commence in FY2025.

Establish New Lafayette 30F2/Hopkins Hill 63F6 N.O. Feeder Tie:
Re-conductor 7,400 feet (1.40 miles) of 2-1/c-4/0 Al bare conductor with 3-1/c-477 Al spacer cable from Pole 20 Victory Highway, Exeter, RI to Pole 20 Nooseneck Hill Road, Exeter, RI. Install a N.O. Tie PTR at Pole 21 Victory Highway, Exeter, RI. Install a new PTR at Pole 57 Victory Highway, Exeter, RI (63F6 feeder). Remove 2-65K fuses at Pole 20 Nooseneck Hill Road, Exeter, RI (63F6 feeder). Design work is tentatively scheduled to commence in FY2025.

Long Term Recommendation – Estimated Cost Summary

Funding Project Number	STORMS WR No.	Title/Description	Capital ($)	O&M ($)	Removal ($)	Total ($)
	South County Study	Re-conductor 30F from Pole 121 Ten Rod Road, North Kingstown, RI to Pole 44 Ten Rod Road, Exeter, RI.	$1,806,000	$144,000	$228,900	$2,178,900
	South County Study	Establish New Lafayette 30F2/Hopkins Hill 63F6 N.O. Feeder Tie	$1,423,500	$36,300	$107,800	$1,567,600

CONSIDERATIONS FOR ACTIVE/PENDING STUDIES

Project Description:
There are no active/pending studies affecting this feeder.

Rhode Island Energy™
a PPL company

Memorandum

To: Eric Wiesner

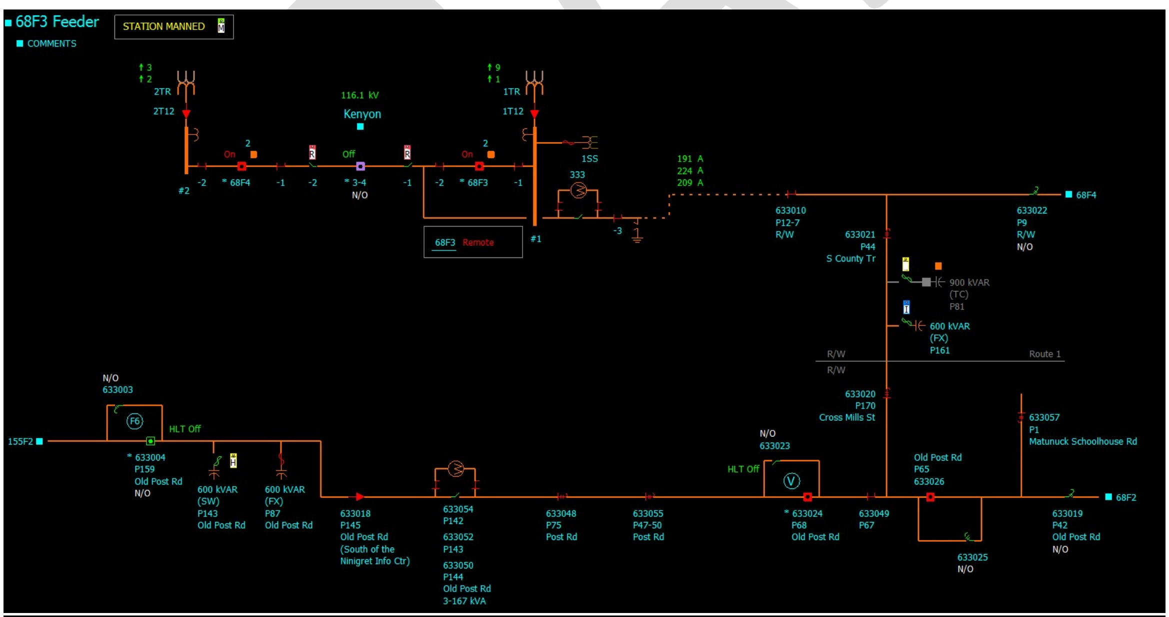
From: Diego Villarreal

Date: Friday, June 16, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 68F3

This memo documents the recommendations to improve CKAIDI on the 2022 Poor Performing **68F3** feeder.

Kenyon 68F3:



- Supplied at 115kV.
- Two transformers five feeder substation.
- Total circuit feet: 22.6 miles.
    - One Phase distance: 52 miles.

- Three Phase distance: 13.2 miles.
- Total connected load: 22343 kVA.
  - Phase A: 6315 kVA
  - Phase B: 8088 kVA
  - Phase C: 7160 kVA
- Three overhead feeder ties with 68F4, 68F2 & 155F2.
- Total customers: 3400.

RELIABILITY PERFORMANCE

This table illustrates both the historical reliability performance as well as the predicted reliability improvement after the changes in this document have been completed.

Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	CKAIDI Performance History 2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Improvements Short Term Work	Long Term Work
	No	56-68F3	40	3191	OH	13.24	122.4	26.6	28.4	73.9	36.8		

Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	CKAIFI Performance History 2022	2021	2020	2019	2018	Improvements Short Term Work	Long Term Work
		56-68F3	40	3191	OH	13.24	3.12	0.19	0.24	1.65	0.61		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 and >= 30 min for CKAIDI)

Circuit 68F3:

CKAIDI:

DAY_TYPE	Estimated CKAIF	Estimated CKAIDI Min	FDR	Feeder _Cs	Year	TIME_OFF	UNIQUE_LOCATION	CAUSE_INTRPTN_DESC	Classification	EVENT CI
Major Storm	0.030	52.102	56-68F3	3191	2020	2/7/2020	56-68F3: CJ: SOUTH COUNTY TRL (1300)	Tree Fell	Fused branch - overhead	97
Major Storm	0.067	82.019	56-68F3	3191	2020	2/7/2020	56-68F3: CLE: OLD COACH RD (0890)	Tree Fell	Fused branch - overhead	214
Major Storm	0.017	31.042	56-68F3	3191	2021	10/27/2021	56-68F3: DBGC: MATUNUCK SCHOOL HOUSE RD (084	Tree - Broken Limb	Fused branch - overhead	55
Major Storm	0.066	80.056	56-68F3	3191	2020	2/7/2020	56-68F3: DBGF: CHARLESTOWN BEACH RD (0840)	Tree Fell	Fused branch - overhead	212
Major Storm	0.040	71.271	56-68F3	3191	2019	10/17/2019	56-68F3: HBB: PROSSER TRL (1093)	Tree Fell	Fused branch - overhead	129
Major Storm	0.045	68.744	56-68F3	3191	2020	2/7/2020	56-68F3: IJ: OLD POST RD (1090)	Tree Fell	Fused branch - overhead	143

The feeder has performed well under the Frequency Indices for the past 5 years. The CKAIDI was significantly influenced by six events that happened during major storms.

COMPLETED WORK

There are 27 reliability Work Requests that have been complete. The work ranges from pole replacements, conductor replacements & sectionalizing fuses installations.

State	City/Town Desc	Feeder Number	WR Number	WR Status Code	Work Request Description	Job Type Code
RI	CHARLESTOWN	56-68F3	2767295	90	Distribution Electric Reliability.Install anchor.	DRELIABLE
RI	CHARLESTOWN	56-68F3	8022395	90	Transfer RAM ISLAND to B-phase, replace damaged grounds, install grounds dm	DRELIABLE
RI	CHARLESTOWN	56-68F3	8398503	90	Distribution Electric Reliability dm	DRELIABLE
RI	CHARLESTOWN	56-68F3	8404511	90	STRAIGHTEN P43-52	DRELIABLE
RI	CHARLESTOWN	56-68F3	8626355	90	2 POWAGET AVE - REPLACE P 1 AND TRANSFER NGRID dm	DRELIABLE
RI	CHARLESTOWN	56-68F3	9377064	90	NESRELFY11- UPGRADE TO 50 KVA dm	DRELIABLE
RI	CHARLESTOWN	56-68F3	9378057	90	NESRELFY11- UPGRADE TO 50 KVA dm 20103500416 08/26/10 0830	DRELIABLE
RI	CHARLESTOWN	56-68F3	9960634	90	P.32 Charlestown Beach Rd Install sidewalk anchor	DRELIABLE
RI	CHARLESTOWN	56-68F3	12652587	90	P2 CENTRAL ST-REPLACE POLE, ANCHOR,OH XFMR & GUY-XFER ELEC (1 -PRI,SEC THRU)	DRELIABLE
RI	CHARLESTOWN	56-68F3	13252355	90	COF 104 SEA BREEZE AVE - P 11 REPLACE POLE & XFMR, TRANSFER NGRID	DRELIABLE
RI	CHARLESTOWN	56-68F3	13344029	90	68F3 Voltage problem house # 50 West Niantic St. - ASAP - AK	DRELIABLE
RI	CHARLESTOWN	56-68F3	13436142	90	68F3 Install 1-900kVAR cap bank at P.39 West Beach Rd ***ASAP***	DRELIABLE
RI	CHARLESTOWN	56-68F3	13474458	90	68F3 Install 3-167 kVA regulators on Pole 142, 143 and 144 Old Post Road	DRELIABLE
RI	CHARLESTOWN	56-68F3	13516929	90	68F3 Transfer Montauk Rd tap @ P.33 Prosser Trl to A-phase	DRELIABLE
RI	CHARLESTOWN	56-68F3	14449924	90	P2 RIDGE RD-REPLACE OH SERVICE TO # 20..NGRID TRIMMING NEEDED	DRELIABLE
RI	CHARLESTOWN	56-68F3	14484153	90	Install 10kVA xfmr on P15 Arnolda Round Road.	DRELIABLE
RI	CHARLESTOWN	56-68F3	14625052	90	REPLACE SECONDARY FROM P2 CROSS ST TO P5-4 EAST CENTRAL AVE	DRELIABLE
RI	CHARLESTOWN	56-68F3	14877115	90	Distribution Electric Reliability	DRELIABLE
RI	CHARLESTOWN	56-68F3	17495941	90	Remove rotted pole P41-84	DRELIABLE
RI	CHARLESTOWN	56-68F3	18920216	90	***ERR***P31 Charlestown Beach Rd, Install (2) Trip Saver	DRELIABLE
RI	CHARLESTOWN	56-68F3	29773669	90	RECONDUCTOR PRIMARY FROM POLE 56 TO POLE 32 W/ 1/0 AL TW	DRELIABLE
RI	CHARLESTOWN	56-68F3	30486678	90	Pole 152-3; install anchor & guy wire	DRELIABLE
RI	CHARLESTOWN	56-68F3	30489760	80	ERR2021 - sectionalizing fuse installation	DRELIABLE
RI	CHARLESTOWN	56-68F3	30607802	80	Replace Pole 2, Replace xfmr w stainless 50kva	DRELIABLE
RI	SOUTH KINGSTO'	56-68F3	30489765	90	ERR2021 - sectionalizing fuse installation	DRELIABLE
RI	WESTERLY	56-68f3	1546160	90	Distribution Electric Reliability.replace service.	DRELIABLE
RI	WESTERLY	56-68F3	16178787	90	Distribution Electric Reliability	DRELIABLE

PENDING WORK

State	City/Town Desc	Feeder Number	WR Number	WR Status Code	Work Request Description	Job Type Code
RI	CHARLESTOWN	56-68F3	30047080	20	Distribution Electric Reliability	DRELIABLE
RI	CHARLESTOWN	56-68F3	30070938	40	UPGR STEP-DOWN X-FMR & UPGRAEE LINES FUSES IN 5 LOCATIONS	DRELIABLE
RI	CHARLESTOWN	56-68F3	30648100	20	3-333kVA Regulator Installation	DRELIABLE
RI	CHARLESTOWN	56-68F3	30657826	20	3-167kVA Removal	DRELIABLE

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Benefits for the short term recommendations are shown in the reliability tables on page 1.

<u>Tree Trimming</u>: **Recommended**
Next cycle in 2024

<u>Infrared Circuit Scan</u>: **Recommended**
Last scan performed in 2019

<u>Animal Mitigation</u>: **Not Recommended**
Not required.

Fault Indicators: **Not Recommended**
Not required.

Load Balancing: **Not Recommended**
Not required.

Protective Device Coordination Review: **Not Recommended**
Not required.

Cutout Mounted Recloser Installations: **Recommended**
WR#:
Scope of work: 30840346
- Replace 65K fuses at P.26 Narrow Ln Charlestown, RI with 600A Solid Blades.
- Install single phase 65k CMR at P.54 Old Coach Rd.

WR#:
Scope of work: 30840347
- Install 1-40K CMR at P.52 Old Coach Rd Charlestown, RI

WR#:
Scope of work: 30840348
- Install 1-40K CMR at P.33 Prosser Trail Charlestown, RI
- Replace existing 3-40k Fuses at P79 Post Rd. with 3-65k Fuses.

Line Recloser Installations: **Recommended**

WR#30794503
- P.65 Old Post Rd Charlestown, RI Form 4 PTR replacement. (18 PTR Replacement Program)

WR#
Scope of work: 30839882
- Install new Viper PTR at P.86-50 Post Rd Charlestown, RI.
- Splits customer count from 1088 customers downstream of existing PTR P.68 Old Post Rd to 517.
- 571 customers downstream of proposed PTR at P86-50

Additional Circuit Sectionalizing: **Not Recommended**

Additional Feeder Ties/Reconfiguration: **Not Recommended**

Other Recommendations: **Recommended**

WR#
Scope of work: 30839921

- Replace existing LB at P.9 with N/O PTR – feeder tie with 68F4.
- 68F4 projected load: 317A (62%).
- Number of customers: 763, +/- 80A.

WR# TBD

- Reconductor from Pole 167 Post Rd Charlestown, RI to Pole 9542 South County Trail Charlestown, RI with 477 Al spacer cable.
- This project can also be sub-divided into four phases:
  ○ **Phase 1**: From P.167 Post Rd to P.132 South County Trail +/- 5320 FT.
  ○ **Phase 2**: From P.132 South County Trail to P.94 South County Trail +/- 5320 FT.
  ○ **Phase 3**: From P.94 South County Trail to P.56 South County Trail +/- 5320 FT.
  ○ **Phase 4**: From P.56 South County Trail to P.9245 South County Trail +/- 4000 FT.
- Additional equipment replacement to be determined by field inspection.

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Memorandum

To: Eric Wiesner

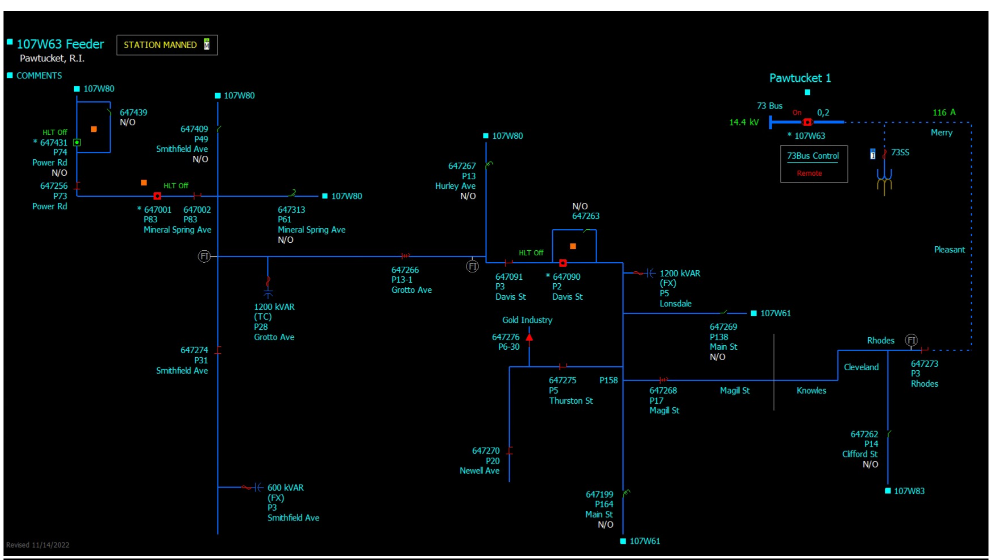
From: Diego Villarreal

Date: Monday, August 28, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 107W63

This memo documents the recommendations to improve CKAIDI on the 2022 Poor Performing **107W63** feeder.

<u>Kenyon 107W63:</u>



- Supplied at 115kV.
- Three transformers eleven feeder substation.
- Total circuit feet: 13.6 miles.
  - One Phase distance: 6.6 miles.

  - Three Phase distance: 7 miles.
- Total connected load: 15747 kVA.
  - Phase A: 4692 kVA
  - Phase B: 2727 kVA
  - Phase C: 3202 kVA
- Three overhead feeder ties with 107W80 (4), 107W83, 107W61 (2).
- Total customers: 3317.

RELIABILITY PERFORMANCE

This table illustrates both the historical reliability performance as well as the predicted reliability improvement after the changes in this document have been completed.

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
	No	53-107W63	19	3152	OH	6.56	25.5	29.3	94.3	103.5	176.4		

							CKAIFI Performance History					After Proposed	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		53-107W63	19	3152	OH	6.56	0.72	1.05	1.57	3.21	2.79		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 and >= 30 min for CKAIDI)

Circuit 107W63:

CKAIDI:

DAY_TYPE	Estimated CKAI	Estimated CKAIDI Min	FDR	Feeder _Cs	Year	TIME_OFF	UNIQUE_LOCATION	CAUSE_INTRPTN_DESC	Classification	EVENT CI	EVENT_CI
Blue Sky	0.974	67.081	53-107W63	3152	2018	8/27/2018	53-107W63: H: MINERAL SPRING AVE (0484)	Device Failed	Main line - overhead	3071	211440.00
Blue Sky	0.447	54.497	53-107W63	3152	2020	1/12/2020	53-107W63: H: MINERAL SPRING AVE (0484)	Device Failed	Main line - overhead	1408	171776.00
Major Storm	0.978	515.691	53-107W63	3152	2019	11/1/2019	53-107W63: H: MINERAL SPRING AVE (0484)	Tree - Broken Limb	Main line - overhead	3084	1625459.00
Blue Sky	0.440	38.283	53-107W63	3152	2023	2/4/2023	53-107W63: H: MINERAL SPRING AVE (0484)	Device Failed	Main line - overhead	1387	120669.00
Blue Sky	1.068	53.300	53-107W63	3152	2019	8/31/2019	53-107W63: A: NO 1 STA YARD (0590)	Vehicle	Main line - overhead	3366	168002.00
Blue Sky	0.988	30.617	53-107W63	3152	2019	1/24/2019	53-107W63: A: NO 1 STA YARD (0590)	Insulation failure - other	Main line - overhead	3115	96505.00
Blue Sky	0.985	64.342	53-107W63	3152	2018	12/15/2018	53-107W63: A: NO 1 STA YARD (0590)	Vehicle	Main line - overhead	3106	202806.00
Major Storm	0.649	51.929	53-107W63	3152	2021	10/27/2021	53-107W63: D: DAVIS ST (0194)	Other Company Activities	Main line - overhead	2046	163680.00
Blue Sky	0.651	34.521	53-107W63	3152	2020	10/30/2020	53-107W63: D: DAVIS ST (0194)	Tree Fell	Main line - overhead	2053	108809.00

COMPLETED WORK

WR#30622003 calls for the installation of a N/O PTR at P.74 Power Rd. Feeder tie with the 107W80.

State	City/Town Desc	Feeder Number	WR Number	WR Status Code	Work Request Description	Job Type Code
RI	PAWTUCKET	53-107W63	9373591	90	NESRELFY11- UPGRADE TRANSFORMER TO A 50 KVA	DRELIABLE
RI	PAWTUCKET	53-107W63	27070276	90	INSTALL RADIO RECLOSER CONTROL	DRELIABLE
RI	PAWTUCKET	53-107W63	30622003	90	Install N/O VIPER Recloser & N/O Bypass at P74; make Discs at P73 N/C	DRELIABLE

PENDING WORK

No pending work.

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Benefits for the short term recommendations are shown in the reliability tables on page 1.

Tree Trimming: **Recommended**

Infrared Circuit Scan: **Recommended**
Last scan performed in 2017

Animal Mitigation: **Not Recommended**
Not required.

Fault Indicators: **Not Recommended**
Not required.

Load Balancing: **Not Recommended**
Not required.

Protective Device Coordination Review: **Not Recommended**
Not required.

Cutout Mounted Recloser Installations: **Recommended**
WR#:
Scope of work:

- P.4 Magill St Pawtucket, RI
- Replace existing k-link fuses with 2-40k CMRs.

WR#:
Scope of work:
- P.2-1 Toledo Ave Pawtucket, RI
- Replace 25k fuse with 65k CMR.

<u>Line Recloser Installations:</u> **Recommended**

WR#
Scope of work:
- Install new Viper PTR at P.5 Magill St Pawtucket, RI
- Splits customer count:
    - 605 customers downstream of Substation.
    - 497 customers downstream from P.5 Magill St to existing PTR at P.2 Davis St.

WR#
Scope of work:
- Install new Viper PTR at P.14 Clifford St Pawtucket, RI – N/O feeder tie with 107W83

<u>Additional Circuit Sectionalizing</u>: **Not Recommended**

<u>Additional Feeder Ties/Reconfiguration</u>: **Not Recommended**

<u>Other Recommendations</u>: **Not Recommended**

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Memorandum – ERR – Feeder 53-38F1

To: Eric Wiesner

From: Mark Fraser

Date: July 26, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-38F1

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-38F1 feeder out of Putnam Pike Substation.

RELIABILITY PERFORMANCE

					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-38F1	20	3117	OH	20.70	119.3	82.6	125.3	120.6	150.5

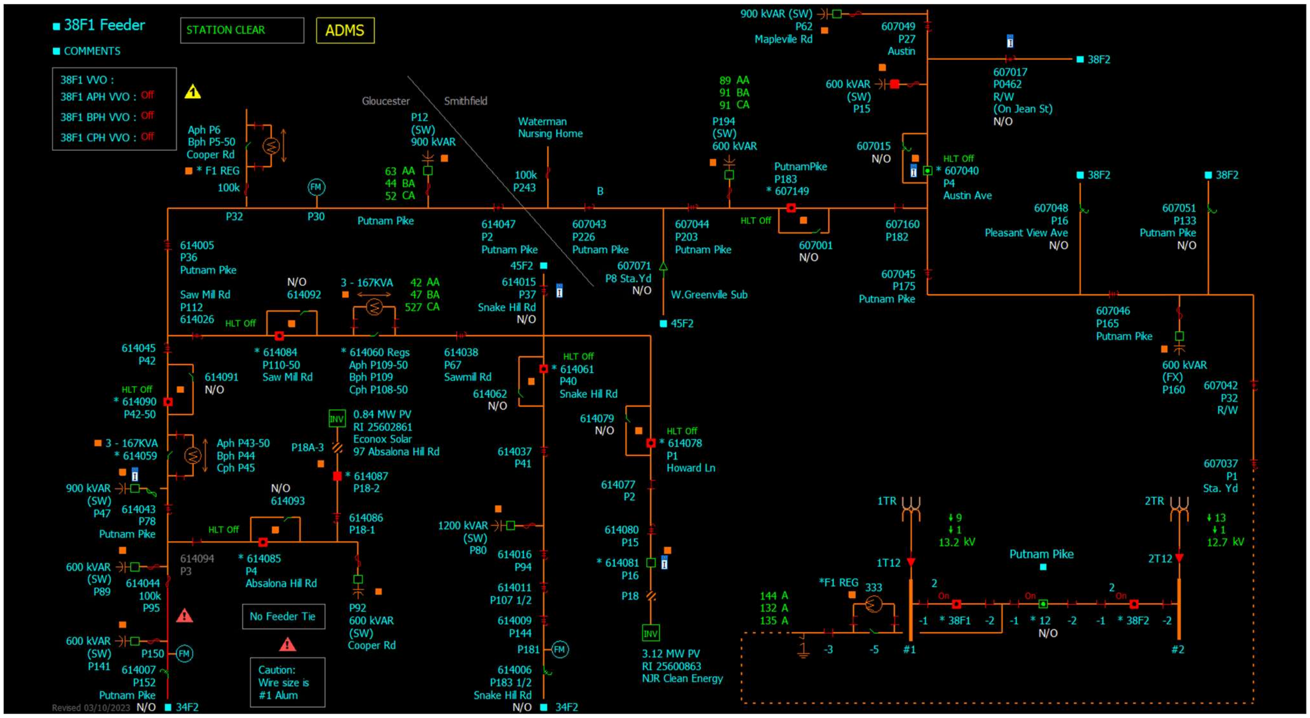
					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-38F1	20	3117	OH	20.70	1.45	0.60	1.57	0.91	2.03

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-38F1

Date	Unique Location	Cause	Day Type	Town	Estimated CKAIFI	Estimated CKAIDI Min
6/30/2018	53-38F1: A: ROME POINT TRANSMISSION #3 (1001)	Device Failed	Blue Sky	GLOCESTER	0.992	53.818
3/13/2018	53-38F1: KAHAK: COOPER RD (0135)	Tree - Broken Limb	Major Storm	SMITHFIELD	0.539	30.252
4/13/2020	53-38F1: KAHAKD: LONG ENTRY RD (0445)	Tree Fell	Major Storm	GLOCESTER	0.526	166.333
3/8/2018	53-38F1: KAHAK: COOPER RD (0135)	Tree - Broken Limb	Major Storm	GLOCESTER	0.411	254.915
1/13/2018	53-38F1: M: SAW MILL RD (0640)	Tree Fell	Blue Sky	SMITHFIELD	0.388	33.321
10/16/2019	53-38F1: K: PUTNAM PIKE (0585)	Tree - Broken Limb	Major Storm	GLOCESTER	0.378	20.391
4/27/2020	53-38F1: L: SAW MILL RD (0640)	Device Failed	Blue Sky	SCITUATE	0.377	21.037
8/4/2020	53-38F1: MEDF: ROCKY HILL RD (0732)	Tree - Broken Limb	Major Storm	GLOCESTER	0.377	398.736
4/25/2020	53-38F1: KA: PUTNAM PIKE (0585)	Vehicle	Blue Sky	GLOCESTER	0.377	28.502
4/13/2020	53-38F1: K: PUTNAM PIKE (0585)	Tree - Broken Limb	Major Storm	GLOCESTER	0.377	18.094
9/26/2020	53-38F1: K: PUTNAM PIKE (0585)	Vehicle	Blue Sky	SCITUATE	0.376	1.129
1/1/2019	53-38F1: K: PUTNAM PIKE (0585)	Unknown	Blue Sky	GLOCESTER	0.376	51.512
10/7/2020	53-38F1: S: HUNTING HOUSE RD (0340)	Tree Fell	Major Storm	GLOCESTER	0.368	86.098
4/26/2022	53-38F1: KA: PUTNAM PIKE (0585)	Construction by Company	Blue Sky	GLOCESTER	0.367	7.757
6/30/2022	53-38F1: K: PUTNAM PIKE (0585)	Construction by Company	Blue Sky	GLOCESTER	0.367	13.935
6/17/2018	53-38F1: M: SAW MILL RD (0640)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.192	9.650
8/4/2020	53-38F1: G: PUTNAM PIKE (1000)	Tree - Broken Limb	Major Storm	GLOCESTER	0.173	68.282
8/4/2020	53-38F1: G: PUTNAM PIKE (1000)	Tree - Broken Limb	Major Storm	SMITHFIELD	0.173	11.413
8/30/2021	53-38F1: N: SNAKE HILL RD (0665)	Vehicle	Blue Sky	GLOCESTER	0.133	0.133
4/21/2022	53-38F1: KA: PUTNAM PIKE (0585)	Device Failed	Blue Sky	GLOCESTER	0.113	0.563
11/1/2019	53-38F1: KAHA: ABSALONA HILL RD (0585)	Tree Fell	Major Storm	GLOCESTER	0.070	163.937
3/3/2018	53-38F1: Q: SNAKE HILL RD (0665)	Tree - Broken Limb	Major Storm	GLOCESTER	0.066	51.975
8/4/2020	53-38F1: CL: PUTNAM PIKE (1000)	Tree - Broken Limb	Major Storm	SMITHFIELD	0.054	83.366
3/7/2018	53-38F1: JH: COOPER RD (0585)	Unknown	Major Storm	GLOCESTER	0.048	35.900
11/1/2019	53-38F1: OL: SANDY BROOK RD (0665)	Unknown	Major Storm	GLOCESTER	0.028	59.256
3/2/2018	53-38F1: CL: PUTNAM PIKE (1000)	Unknown	Major Storm	SMITHFIELD	0.027	41.034
10/31/2019	53-38F1: QE: TOURTELOTTE HILL RD (0665)	Unknown	Major Storm	GLOCESTER	0.024	57.664
11/1/2019	53-38F1: JHF: COOPER RD (0135)	Unknown	Major Storm	GLOCESTER	0.019	37.081
3/2/2018	53-38F1: JHF: COOPER RD (0135)	Tree Fell	Major Storm	GLOCESTER	0.018	51.097
3/2/2018	53-38F1: JHE: FARNUM RD (0135)	Tree Fell	Major Storm	GLOCESTER	0.017	71.792

One Line Map of the 38F1 Feeder



Completed Work

Over the last five years, 67 reliability Work Requests have been completed. These include addition of pole replacements, transformer installations, primary wire replacements, regulator installations, capacitor bank upgrades, and fuse additions.

Twon	Feeder	WR	Status	Work Request Description	Job Type
SMITHFIELD	53-38F1	24944071	90	Distribution Electric Asset Replacement 2/4hrs -	DASSETREPL
GREENVILLE	53-38F1	24010940	90	Distribution Electric Asset Replacement PO 3/8HR EO 4/16HR DD 2/12	DASSETREPL
SMITHFIELD	53-38F1	23652599	90	Distribution Electric Asset Replacement 4/8hrs	DASSETREPL
SMITHFIELD	53-38F1	26783426	90	Distribution Electric Asset Replacement 2/6hrs 645	DASSETREPL
GLOCESTER	53-38F1	26442909	90	RELOC P.32 TO PREV LOC AND REPL PUSH BRACE - STORM ISSUE 4/8H DD9/4	DASSETREPL
SCITUATE	53-38F1	23876051	90	OPEN WIRE SEC REHAB / REPLACE 5 SECT SEC - NEUT / NO POLE SETs NEEDED kid/10D	DASSETREPL
SCITUATE	53-38F1	23876101	90	UPGRP9, P-1 & 9-2 / REM JUNK SEC RUN NEW 3/C-1/0 SEC po2/8 eo4/8h dd4/19	DASSETREPL
SMITHFIELD	53-38F1	28071104	90	Distribution Electric Asset Replacement 4/6h dd7/11	DASSETREPL
HARMONY	53-38F1	23209469	90	Distribution Electric Asset Replacement PO 2/2D EO4/8H dd5/10 11.14%exp	DASSETREPL
SMITHFIELD	53-38F1	23846260	90	Distribution Electric Asset Replacement	DASSETREPL
GLOCESTER	53-38F1	28488679	90	Reloc P76-513' West away fr hseRem tree guy 4/8H 637dd9/20 226.33%EXP	DASSETREPL
SMITHFIELD	53-38F1	607835	90	38F1- Feeder Hardening- Condemned Pole	DASSETREPL
GLOCESTER	53-38F1	29756790	90	Replace P2 w/ 45' H1. Replace airbreak w/ lloadbreak switch dm	DASSETREPL
GLOCESTER	53-38F1	27041552	90	Distribution Electric Asset Replacement dm	DASSETREPL
GLOCESTER	53-38F1	29004918	90	REPLACE PL 86 W/ 45 CL2 & 85-50 W/ 35 CL3 ADDED $800 FOR POLICE DETAIL dm	DASSETREPL
GLOCESTER	53-38F1	30325145	90	Transfer attachements to new pole 51-2.	DASSETREPL
SMITHFIELD	53-38F1	28088628	90	Replace LB with hookstick, transfer 45F2 and 38F1 primary, secondary, Replace P	DASSETREPL
GLOCESTER	53-38F1	30325336	90	Replace transformer and transfer facilities to new pole.	DASSETREPL
GLOCESTER	53-38F1	30325171	90	Transfer attachments to replaced pole & pushbrace	DASSETREPL
GLOCESTER	53-38F1	30325378	90	TRANSFER FACILITIES @ P38, P39, P49 & P51 - REPL XFORMER @ P49	DASSETREPL
GLOCESTER	53-38F1	30445021	90	REPL 25KVA W/ 50KVA @ P19	DASSETREPL
SMITHFIELD	53-38F1	26316124	90	Replace wire between LP 20 - LP 21, 5/16/18, Aspen Ln., Smithfield, RI, Fdr 38F1	DCONFRMWO
SMITHFIELD	53-38F1	29722379	90	Equipment Repl, 4/29/20, Pole 193, Putnam Pike, Smithfield, RI, Fdr#38F1	DCONFRMWO
GLOCESTER	53-38F1	29731824	90	Various Equipment, 5/4/20, Pole 1-50, Tarklin Rd, Glocester, RI, Fdr#N/A	DCONFRMWO
SMITHFIELD	53-38F1	29764578	90	Equip Damage, 5/20/20, Pole 1, Cherry Blossom Ln, Smithfield, RI, Fdr#N/A	DCONFRMWO
GLOCESTER	53-38F1	29778938	90	Cross-arm Repl, 5/27/20, Pole 123, Putnam Pike, Glocester, RI, Fdr#38F1	DCONFRMWO
SCITUATE	53-38F1	25686833	90	XFMR POLE LEANING/ TREE DAMAGE/ REPLACE -UPGR ANCHOR 4/6H DD5/14	DDAMAGE
GLOCESTER	53-38F1	27402440	90	Replace damaged sections of 1/0 triplex P.3 to P.4 4/3HRS 100%capex	DDAMAGE
CHEPACHET	53-38F1	30030983	90	REPL BROKEN P47-1, SECONDARY, CONN TO AUG & REPL MTR WTG 605	DDAMAGE
GLOCESTER	53-38F1	30126218	90	REMV TREE GUY, INST STUB P14-84, DOWN GUY, AND POLE TO POLE GUY @ P14 > P14-84	DDAMAGE
GLOCESTER	53-38F1	30380277	90	REPLACE DAMAGE MINI-PAD # 59-54	DDAMAGE
GREENVILLE	53-38F1	30524230	90	Distribution Electric Damage/Failure-N/B	DDAMAGE
GLOCESTER	53-38F1	21812434	90	DOTR-Relocate P.40 Putnam Pike (at of Saw Mill Road), PO 2/8H EO4/12H DD3/28	DENEDOT
SMITHFIELD	53-38F1	29965047	90	XFER TAP FROM B PHASE TO C PHASE FOR CODY DR., GLOC & BALDWIN DR., SMITHF	DLOADRELF
SMITHFIELD	53-38F1	30483733	90	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - CAP P62	DLOADRELF
SMITHFIELD	53-38F1	30483731	90	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - CAP P15	DLOADRELF
GLOCESTER	53-38F1	30465996	90	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - REGS P108-50	DLOADRELF
GLOCESTER	53-38F1	30441573	80	RIVVO2021-PUTNAM PIKE RETROFIT-LVM P181	DLOADRELF
GLOCESTER	53-38F1	30483734	80	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - CAP P12	DLOADRELF
SMITHFIELD	53-38F1	30483738	80	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - CAP P160	DLOADRELF
SMITHFIELD	53-38F1	30483739	80	RIVVO2021-PUTNAM PIKE RETROFIT - 38F1 - CAP P194	DLOADRELF
GREENVILLE	53-38F1	23939501	90	Replace Pin Insulators 4/3HRS	DMAINT-G
NORTH SCITUATE	53-38F1	29501733	90	REPL XFORMER @ P7-8 W/ 50KVA	DPUBLICDG
GLOCESTER	53-38F1	26239285	90	RELOC EXIST P.8-84 TO RAISE PRIM - REPLACE SERV - SS PO2/4H EO4/4H DD1/14 1.85%	DPUBLICRQ
GLOCESTER	53-38F1	27402336	80	Remove usused triplex P.16 to P.17 4/2hr	DPUBLICRQ
GLOCESTER	53-38F1	27402401	80	Repl p21 & 22 w/40ft cl-3 P repl 15kVA XFMR w/25kVA XFRM po4/8h eo 4/8hdd2/25	DPUBLICRQ
GLOCESTER	53-38F1	28634155	90	install/remove PTP guy from P.18 to P.18-1, remove old P.18-1 2/4h	DPUBLICRQ
SMITHFIELD	53-38F1	29697678	90	Distribution Electric Public Requirement dm	DPUBLICRQ
SMITHFIELD	53-38F1	29784318	90	Distribution Electric Public Requirement dm	DPUBLICRQ
SMITHFIELD	53-38F1	30109334	80	Distribution Electric Public Requirement	DPUBLICRQ
SMITHFIELD	53-38F1	30291964	90	Replace poles - Low wires - VZ request	DPUBLICRQ
GREENVILLE	53-38F1	30372712	90	Distribution Electric Public Requirement	DPUBLICRQ
CHEPACHET	53-38F1	30464363	90	REMV TRIPLEX P75>P75-1 & POLE 75-1	DPUBLICRQ
GLOCESTER	53-38F1	30549721	80	INST MID-SPAN P30-50 & PUSH BRACE # 32-89	DPUBLICRQ
GLOCESTER	53-38F1	30611690	90	Distribution Electric Public Requirement	DPUBLICRQ
CHEPACHET	53-38F1	30642506	90	Distribution Electric Public Requirement	DPUBLICRQ
SMITHFIELD	53-38F1	16809467	90	Reconductor P171 to P179 Putnam Pike Replace poles&equip 4/14D DD 3/3	DRELIABLE
GLOCESTER	53-38F1	25955059	90	Inst line cutout fused at 40K P105 Long Entry Rd give to svc truck	DRELIABLE
GLOCESTER	53-38F1	25799740	90	REPLACED BAD POLE PO 2/3H EO 4/3H DD5/14	DRELIABLE
GLOCESTER	53-38F1	18002407	90	VZ TO INSTALL STUB POLE AND ANCHOR..NG TO INSTALL P-P GUY AND DOWN ANCHOR	DRELIABLE
GLOCESTER	53-38F1	28847300	90	REPLACE (3) 100K FUSES FEEDING COOPER RD TAP W/ (3) 100K CMR'S	DRELIABLE
SMITHFIELD	53-38F1	27070459	90	INSTALL RADIO RECLOSER CONTROL	DRELIABLE
GLOCESTER	53-38F1	29790435	90	REPLACE 100K FUSE W/ 65K @ POLE 106-50 CORNER DOUGLAS HOOK & COOPER RD	DRELIABLE
GLOCESTER	53-38F1	29558131	90	REPL THE NORTHERN FUSE ON P114 SNAKE HILL RD., W/ CMR dm	DRELIABLE
GLOCESTER	53-38F1	30340982	80	Replace 8 poles,7 transformers, install 4800' 1/0 tree,See WR 30392551	DRELIABLE
GLOCESTER	53-38F1	30392551	90	Remove 100KVA step down, refuse 22 transformers-See WR30340982	DRELIABLE
SMITHFIELD	53-38F1	30731338	80	Distribution Electric Reliability	DRELIABLE

Pending Work

There are 4 open reliability work requests from 2022 and prior. These include a large primary wire upgrade, a pole relocation, new capacitor installation, and metering upgrade. Additional upgrades are planned as part of an area study. A new recloser is being installed and there are some circuit reconfigurations planned.

2023 Recommendations

These recommendations reflect both short-term projects and possible long-term improvements. This circuit is also under review from the System Planning group. A new recloser is being added to the circuit along with load balancing with adjacent feeders.

Title/Description	Category	Est. Cost	Storms WO	Status	Customers Served	Est. Customer Min Saved
Replace Phase C 100K CMR with a 100K fuse at P5 Putnam Pike. There are only 5 customer on this phase which is not enough to charge to CMR which could lead to non-operations for a fault. Glocester	ERR	$488	30791655	Complete	5	
Add a 40K fuse at P36 to reduce fault exposure to the main line. Glocester	ERR	$707	30791658	Complete	55	2,189
Replace 65 K fuse at P32 Cooper Road looking toward P14 Farnum Road with a 65 K CMR. Glocester	ERR		30791627	Complete	55	2,640
Replace 65 K fuse at P36 Cooper Road with a 65 K CMR. Glocester	ERR		30791627	Complete	59	1,416
		$26,138	30791627	Complete		4,056
Install new Tie PTR at P38 Snake Hill Road to replace LBS 614015. North Scituate.	PTR	$84,149	30791580	On Hold	420	14,784

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in September of 2020.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Animal caused outages resulted in less than .2% of the outage minutes over the last 5 years. No additional mitigation efforts are planned at this time.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
System planning has been monitoring and is actively rebalancing this circuit.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations (include Form3s):
See the recommendations above.

Additional Circuit Sectionalizing:
This is not at this time.

Additional Feeder Ties/Reconfiguration:
There is a request to enhance the circuit tie on Snake Hill between the 38F1 and the 45F2.

Protective Device Coordination Review:
This is not necessary at this time.

Other Recommendations:
None

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Memorandum – ERR – Feeder 53-69F3

To: Eric Wiesner

From: Mark Fraser

Date: July 26, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-69F3

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-69F3 feeder out of Manton Substation.

RELIABILITY PERFORMANCE

					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-69F3	27	4757	OH	6.17	115.9	4.9	72.3	48.7	25.5

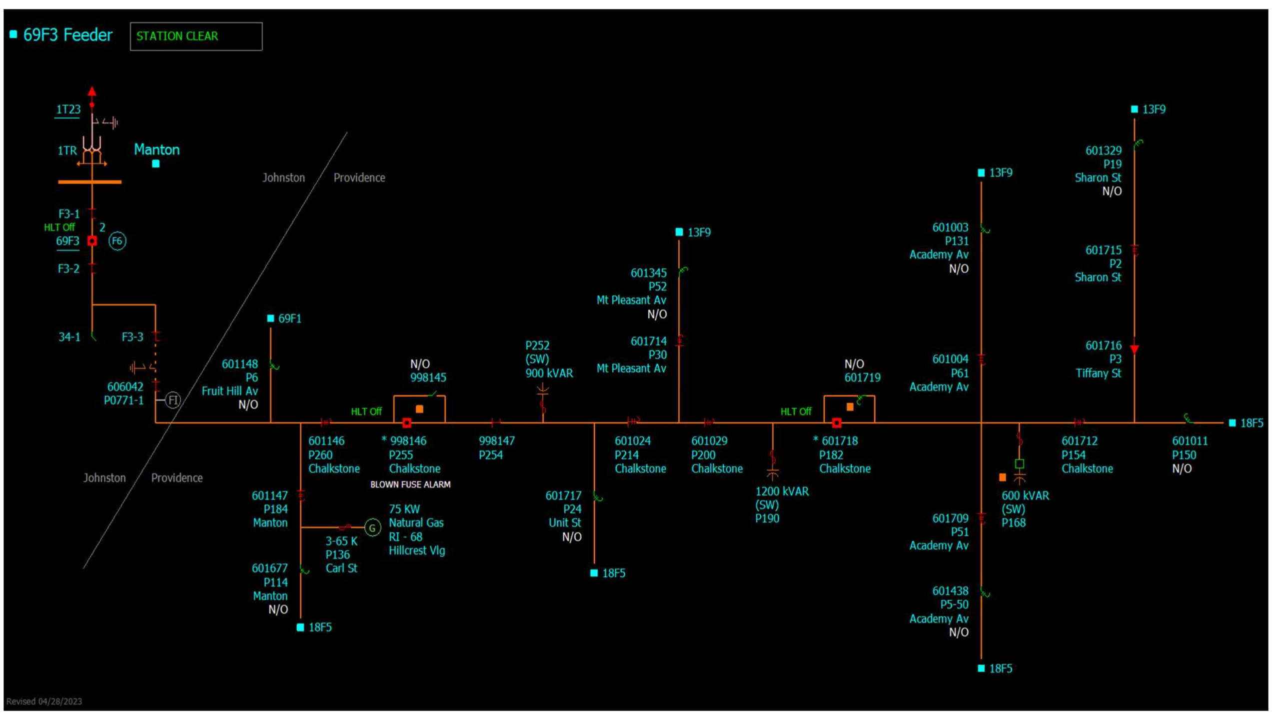
					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-69F3	27	4757	OH	6.17	2.47	0.06	1.05	0.47	0.47

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-69F3

	Unique Location	Cause	Day Type	Town	Estimated CKAIFI	Estimated CKAIDI Min
10/27/2021	53-69F3: A: LYMANSVILLE TAP (8118)	Tree Fell	Major Storm	NORTH PROVIDENCE	1.745	901.544
4/14/2023	53-69F3: D: CHALKSTONE AVE (0625)	Vehicle	Blue Sky	PROVIDENCE	0.997	61.583
4/14/2022	53-69F3: F: CHALKSTONE AVE (0625)	Vehicle	Blue Sky	PROVIDENCE	0.976	48.761
10/31/2020	53-69F3: F: CHALKSTONE AVE (0625)	Tree Fell	Blue Sky	PROVIDENCE	0.969	65.494
8/12/2022	53-69F3: F: CHALKSTONE AVE (0625)	Vehicle	Blue Sky	PROVIDENCE	0.967	45.064
1/25/2019	53-69F3: F: CHALKSTONE AVE (0625)	Device Failed	Blue Sky	PROVIDENCE	0.442	45.925
6/9/2022	53-69F3: F: CHALKSTONE AVE (0625)	Flying Debris	Blue Sky	PROVIDENCE	0.439	14.924
3/2/2018	53-69F3: HA: PLEASANT VALLEY PKWY (4617)	Unknown	Major Storm	PROVIDENCE	0.018	74.144

One Line Map of the 38F1 Feeder



Completed Work

Over the last five years, 14 reliability Work Requests have been completed. These include a recloser installation, pole sets, and secondary wire upgrades.

Town	Feeder	WR No.	WR Status Code	Work Request Description	Job Type Code
PROVIDENCE	53-69F3	25622441	90	Install radio antenna for recloser - Distribution Electric Reliability	DRELIABLE
PROVIDENCE	53-69F3	28117251	90	Replace broken Pole - Distribution Electric Asset 39.00% EXPENSE	DASSETREPL
PROVIDENCE	53-69F3	28208183	90	Replace Pin Insulators 100% EXPENSE	DMAINT-G
PROVIDENCE	53-69F3	29951048	90	INSTALL 25KVA TRANSFORMER ON P28 & FUSE @10K dm	DRELIABLE
PROVIDENCE	53-69F3	30323664	80	Transfer to new pole dm NJUNS	DPUBLICRQ
PROVIDENCE	53-69F3	30336136	80	DOTR - Intersection Safety Improvements Pole 41-50 Mt. Pleasant Ave.	DENEDOT
PROVIDENCE	53-69F3	30489027	90	Distribution Electric Public Requirements for Distributed Generation Projects	DPUBLICDG
PROVIDENCE	53-69F3	30597033	90	Distribution Electric Reliability dm	DRELIABLE
PROVIDENCE	53-69F3	30647433	80	Distribution Electric Reliability dm of the 100 recolosers dm	DRELIABLE
PROVIDENCE	53-69F3	30657540	80	Distribution Electric Damage/Failure-N/B, Capacitor Replacement dm	DDAMAGE
PROVIDENCE	53-69F3	30694922	80	Distribution Electric Load Relief dm	DLOADRELF
PROVIDENCE	53-69F3	30697493	80	Voltage Complaint NEEDS DONE ASAP	DLOADRELF
PROVIDENCE	53-69F3	30703124	80	See WR 30707883 for Triplex installation - Line Ops - Other	DMAINT-G
PROVIDENCE	53-69F3	30707883	90	Replace triplex to P.128 - Distribution Electric Damage/Failure-N/B	DDAMAGE

Pending Work

There are 4 open reliability work requests from 2022 and prior. These related to adding additional recloser and radio support for the circuit.

2023 Recommendations

These recommendations reflect both short-term to mid-term improvements projects. There have been protection reviews and updates on this circuit. Also, a PTR was installed near the beginning of the circuit in 2023 to address a number of vehicle accidents on the feeder backbone.

Title/Description	Category	Est. Cost	Storms WO	Status	Customers Served	Est. Saved CM/Yr
Install a new PTR on the 2211 circuit near P9769 ROW behind Manton SS. This would be on the Johnston side of the tap to Manton SS. This is 23 kV. One outage - 8,400 customers - 4,200,000 customer minutes. Better sectionalization needed.	PTR	$100,000		Requires further Engineering Review	4,737	840,000
The eastern end of the 69F3 circuit could use some automated tie switches. The apparent strongest tie is with the 13F9 at P131 Academy Ave.	PTR	$83,000		Requires further Engineering Review	2,172	92,962

General Recommendations:

Tree Trimming:
Maintenance Tree Trimming was completed on the circuit in May of 2019.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Animal caused outages resulted in than .2% of the outage minutes over the last 5 years. No additional mitigation efforts are planned.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
This is not recommended at this time.

Cutout Mounted Recloser Installations:
No CMRs are recommended at this time.

Line Recloser Installations (include Form3s):
See the recommendations above.

Additional Circuit Sectionalizing:
As the circuit ties become automated, customer blocks should be reduced to 500 to 750 customers.

Additional Feeder Ties/Reconfiguration:
See recommendations above.

Protective Device Coordination Review:
Some improvements have occurred recently. No additional review is recommended at this time..

Other Recommendations:
None

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Memorandum – CEMI and ERR – Feeder 53-126W50

To: Eric Wiesner

From: Mark Fraser

Date: July 17, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-126W50

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-126W50 feeder out of Washington Substation.

RELIABILITY PERFORMANCE

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
Mark Fraser	No	53-126W50	9	1608	Mixed	11.04	96.6	311.3	294.5	372.1	165.3		

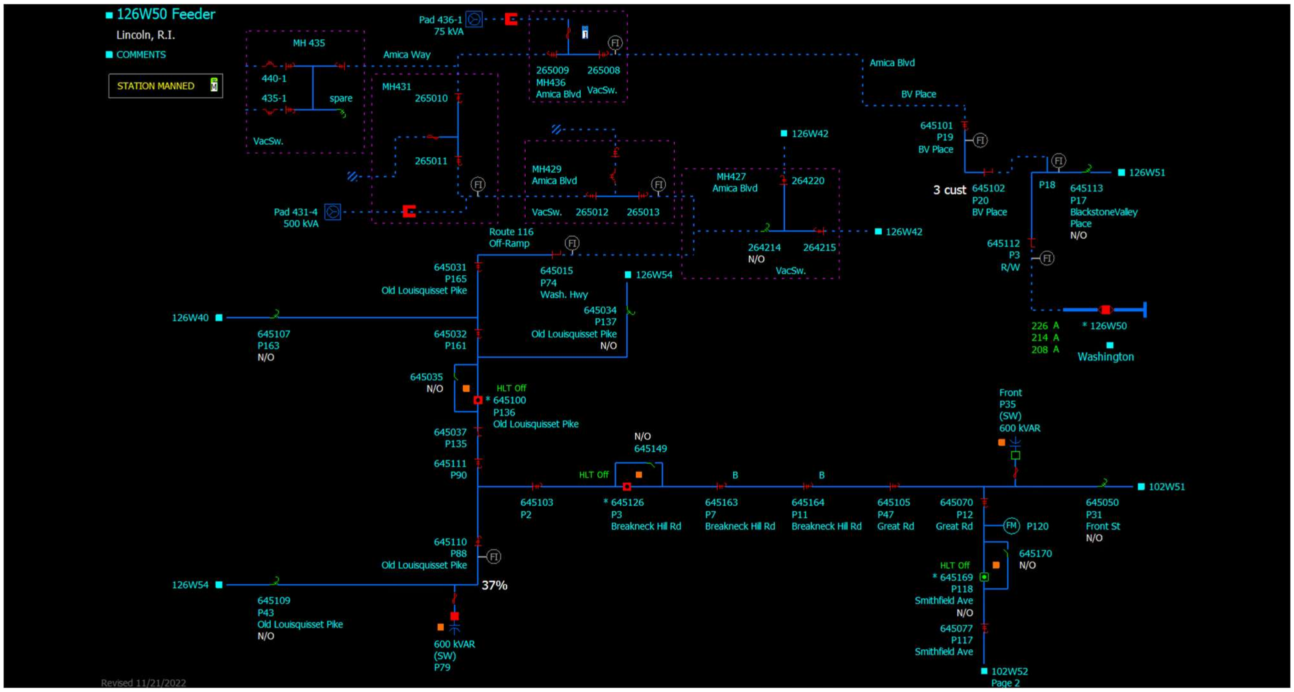
							CKAIFI Performance History					After Proposed	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		53-126W50	9	1608	Mixed	11.04	0.99	6.90	4.35	6.88	1.62		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-126W50

Date	UNIQUE LOCATION	Cause	Day Type	Town	Estimated CKAIFI	Estimated CKAIDI Min
2/7/2020	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Major Storm	SMITHFIELD	2.991	1108.576
8/13/2018	53-126W50: D: BLACKSTONE VLY PL (0414)	Device Failed	Blue Sky	SMITHFIELD	2.532	63.044
5/15/2019	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	SMITHFIELD	1.009	1.009
2/3/2021	53-126W50: E: Road_not_found (0450)	Device Failed	Blue Sky	LINCOLN	1.007	28.623
11/1/2020	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	SMITHFIELD	1.007	31.212
8/12/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Fell	Blue Sky	LINCOLN	1.006	31.373
11/1/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Major Storm	LINCOLN	1.001	421.524
5/24/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Growth	Blue Sky	LINCOLN	1.001	146.690
10/11/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	LINCOLN	1.001	26.016
5/9/2020	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	SMITHFIELD	0.999	116.371
4/24/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Non-Company Activities	Blue Sky	LINCOLN	0.995	20.902
7/17/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	SMITHFIELD	0.970	99.131
4/30/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Fell	Blue Sky	SMITHFIELD	0.965	38.463
9/19/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Animal	Blue Sky	SMITHFIELD	0.965	23.224
12/2/2019	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	LINCOLN	0.964	30.846
9/8/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Unknown	Blue Sky	LINCOLN	0.958	66.082
3/2/2018	53-126W50: ODA: OLD JENKS HILL RD (0412)	Tree Fell	Major Storm	SMITHFIELD	0.659	887.262
5/8/2021	53-126W50: S: GREAT FT19 RD (0362)	Vehicle	Blue Sky	LINCOLN	0.502	9.627
3/16/2021	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Blue Sky	LINCOLN	0.502	0.502
8/4/2020	53-126W50: RK: GREAT FT19 RD (0362)	Tree Fell	Major Storm	LINCOLN	0.501	998.175
3/2/2018	53-126W50: S: GREAT FT19 RD (0362)	Tree Fell	Major Storm	LINCOLN	0.501	587.476
5/22/2022	53-126W50: S: GREAT FT19 RD (0362)	Vehicle	Blue Sky	LINCOLN	0.501	36.768
5/13/2019	53-126W50: S: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.501	22.641
10/7/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Lightning	Major Storm	LINCOLN	0.501	275.342
9/30/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Major Storm	LINCOLN	0.501	21.527
4/26/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Blue Sky	LINCOLN	0.501	17.021
10/30/2020	53-126W50: T: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.500	27.108
6/30/2021	53-126W50: T: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.499	22.591
8/19/2019	53-126W50: PAJMC: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.421	7.999
8/4/2020	53-126W50: PAJ: UNKNOWN86 ST (0154)	Tree - Broken Limb	Major Storm	SMITHFIELD	0.267	378.265
6/9/2021	53-126W50: PAJ: UNKNOWN86 ST (0154)	Tree Fell	Blue Sky	SMITHFIELD	0.230	23.010
9/18/2022	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.130	6.239
10/23/2018	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.127	38.440
2/25/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Major Storm	LINCOLN	0.123	21.807
8/23/2022	53-126W50: PAJL: ANGELL RD (0078)	Lightning	Blue Sky	LINCOLN	0.108	6.348
7/22/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.107	6.632
9/7/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.106	7.550
8/16/2020	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.104	10.178
7/2/2022	53-126W50: V: WOODLAND ST (0411)	Tree Fell	Blue Sky	LINCOLN	0.089	30.325
8/4/2020	53-126W50: PD: JENCKES HILL RD (0110)	Unknown	Major Storm	LINCOLN	0.030	55.095
4/23/2023	53-126W50: V: WOODLAND ST (0411)	Tree Fell	Blue Sky	LINCOLN	0.090	18.090

One Line Map of the 126W50 Feeder



Completed Work

Over the last five years, 79 reliability Work Requests have been completed. These include addition of pole upgrades, transformer installations, capacitor bank additions, and fuse additions.

Twon	Feeder	WR Numb	WR Status	Work Request Description	Job Type
RI LINCOLN	53-126W50	15476221	90	126W50 priority D2M Computapole inspection WR for overhead.	DASSETOH2
LINCOLN	53-126W50	30438021	90	126W50 priority Level 9 Computapole inspection WR for overhead	DASSETOH2C
RI LINCOLN	53-126W50	15476220	90	126W50 priority D2C Computapole inspection WR for overhead - 521 locations.	DASSETOH2C
LINCOLN	53-126W50	346999	90	102W51 - Feeder Hardening - Condemned Pole	DASSETREPL
LINCOLN	53-126W50	3986358	90	Xarm Replacement	DASSETREPL
LINCOLN	53-126W50	3986367	90	Xarm Replacement	DASSETREPL
LINCOLN	53-126W50	8180359	90	Replace Cable & Xfmrs	DASSETREPL
LINCOLN	53-126W50	9344701	90	UPGRADE PAD TO 50 KVA	DASSETREPL
LINCOLN	53-126W50	11286454	90	126W50Telco replace P94 (40/3); upgrade XFMR (50kva); replace dnguy; transferdm	DASSETREPL
LINCOLN	53-126W50	12722969	90	126W50 Replace rusted minipad T3-10; Re-feed T1-7 dm SUGRUE	DASSETREPL
LINCOLN	53-126W50	12913997	90	126W50 P 80 TWIN RIVER RD -XFER ELEC TO TELCO REPLACED POLE	DASSETREPL
LINCOLN	53-126W50	13095520	90	126W50 VZ Pole replacement dm	DASSETREPL
LINCOLN	53-126W50	15191957	90	P9 ROCKY CLIFF DR-TRANSFER ELEC TO TELCO REPLACED POLE....POLE SET-YESdm	DASSETREPL
LINCOLN	53-126W50	15577140	90	Replace submersible xfmr w/minipad-Distribution Electric Asset Replacement ml	DASSETREPL
LINCOLN	53-126W50	16066894	90	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	19678699	90	Verizon has replaced P9 Angell Rd - 40'/2 Pole. Ngrid to transfer to new pole	DASSETREPL
LINCOLN	53-126W50	23185526	90	Distribution Electric Asset Replacement 4/4HRS	DASSETREPL
LINCOLN	53-126W50	23861333	90	Verizon replaced broken P4A1 622	DASSETREPL
LINCOLN	53-126W50	30315234	80	Replace direct buried cable with CIC via HDD method. Install CIC and new riser.	DASSETREPL
LINCOLN	53-126W50	23875873	90	Distribution Electric Asset Replacement 2/16 4 KIDS	DASSETREPL
LINCOLN	53-126W50	23875985	90	open wire replacement - P99-30 kids 2/hrs	DASSETREPL
LINCOLN	53-126W50	23883426	90	open wire replacement for: P1, 2, AND 3 kids 2 days	DASSETREPL
LINCOLN	53-126W50	26964694	90	UG switch replacement - Amica office park, Lincoln .89% EXPENSE 1/12/19	DASSETREPL
LINCOLN	53-126W50	27213457	90	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	27278422	90	Remove submersible switch & install OH & UG fault indicators 5.81% EXPENSE 622	DASSETREPL
LINCOLN	53-126W50	28331564	90	replace 25KVA W/ 50KVA, replace P71 & anchor W/ 40/3	DASSETREPL
LINCOLN	53-126W50	28677041	90	REPL P136 W/ 50' H1, REPL RECL W/ VIPER RECL Recls discontinued order	DASSETREPL
SMITHFIELD	53-126W50	28331260	90	Distribution Electric Asset Replacement - open wire dm	DASSETREPL
LINCOLN	53-126W50	22233433	90	7/11/2016, Pad 436, Amica Center Blvd, Lincoln RI, fdr #126W50.	DCONFRMWO
LINCOLN	53-126W50	23686884	90	Install 300' cable, 2/28/17, HH 3-1 - HH 3-5, Sylvia Dr, Lincoln, RI, Fdr 126W50	DCONFRMWO
LINCOLN	53-126W50	26849988	90	Replace vac. switch, 8/14/2018, MH 43 RI, Fdr. 126W50 9.55% EXPENSE	DCONFRMWO
LINCOLN	53-126W50	30492357	90	UG Fault, 11/10/21, Pad 1, Amica Center Blvd, Lincoln, RI., Fdr 126W50	DCONFRMWO
LINCOLN	53-126W50	30524751	90	1/4/22, Poles 8, 11, 15, Amica Center Blvd, Lincoln, RI, Fdr 126W50-Partial Comp	DCONFRMWO
LINCOLN	53-126W50	7748849	90	126W50 P9 ROCKY CLIFF RD - POLE SPLIT-TELCO TO REPLACE-TRANSFER NGRIDdm	DDAMAGE
LINCOLN	53-126W50	19811893	90	Replacement of 5 wood streetlight at the intersection of Dennell Dr & Lennon dm	DDAMAGE
LINCOLN	53-126W50	22768992	90	Distribution Electric Damage/Failure-N/B 2/4hrs good for apprentices	DDAMAGE
LINCOLN	53-126W50	30060858	80	Repl P.50-31 & remv 1/0 triplx P50-32 >P.50-33, verizon 2 remv p50-33	DDAMAGE
LINCOLN	53-126W50	23303994	90	Distribution Electric Damage/Failure-N/B 2/2hrs good for apprentices	DDAMAGE
LINCOLN	53-126W50	26390325	90	Replace rotted pole backyard kids BY mach 645	DDAMAGE
LINCOLN	53-126W50	26434228	90	Replace P131-30 (35/3); Telco remove old pole; transfer secondaries 2/4hr dd9/14	DDAMAGE
LINCOLN	53-126W50	28145326	90	Distribution Electric Damage/Failure-N/B 100%CAPEX KIDS/4H dd4/18	DDAMAGE
LINCOLN	53-126W50	28644545	90	REPL RECL SW# 645126. INST LB ON P3 SW#645150 PO4/4H EO 4/3.5D DD10/3	DDAMAGE
LINCOLN	53-126W50	30279253	90	Replace wood light pole with direct buired 14Ff tfiberglass pole, tradional head	DDAMAGE
LINCOLN	53-126W50	30350220	90	Replace handhole cover @ HH1-8 (closest to street light)	DDAMAGE
LINCOLN	53-126W50	30402045	80	DOTR - Bridge Group 39 - Break Neck Hill Road Bridge	DENEDOT
LINCOLN	53-126W50	857253	90	126W50 OLT dm	DLOADRELF
LINCOLN	53-126W50	2217191	90	OS FY08 TRANS OVERLOAD	DLOADRELF
LINCOLN	53-126W50	2217658	90	126W50 OS FY08 TRANS OVERLOAD dm	DLOADRELF
LINCOLN	53-126W50	16865903	90	Transformer change-out from a 25kva to a 50kva unit.	DLOADRELF
LINCOLN	53-126W50	30337880	80	OLT REPLC 2 XFMRS W/ 50KVA	DLOADRELF
LINCOLN	53-126W50	18946299	90	Installing new 50kva transfoerm on P5 Twin River Rd	DLOADRELF
LINCOLN	53-126W50	23073665	90	Distribution Electric Load Relief 4/8hrs -100%CAPEX	DLOADRELF
LINCOLN	53-126W50	25851946	90	Distribution Electric Load Relief - Install LVM on P120 VVO 4/8h dd 2/6	DLOADRELF
LINCOLN	53-126W50	25888804	90	Dist Elec Load Relief - Replace P35 and Intall Advance Cap Bank VVO 4/2D DD12/11	DLOADRELF
LINCOLN	53-126W50	25963297	90	Distribution Electric Load Relief - Repl Cap Bank with Smart VVO 4/12h	DLOADRELF
LINCOLN	53-126W50	27249210	90	Distribution Electric Load Relief, repl 50kva with 100kva padmount 4/3HR 100%cap	DLOADRELF
LINCOLN	53-126W50	29848486	90	Refuse LCO @ P.21 w/25K fuse. Replace LCO @ P.4 w/40K fuse.dm	DLOADRELF
LINCOLN	53-126W50	29850015	90	P.27 - transfer load to A-phase. P.42 - transfer load to A phase dm	DLOADRELF
LINCOLN	53-126W50	29850557	90	P.74 - change tap to C-phase, P.91 - transfer tap to A-phase dm	DLOADRELF
TIVERTON	53-126W50	22223433	90	Distribution Electric Load Relief OLT(1) 4/4h 645 23.76%EXP	DLOADRELF
LINCOLN	53-126W50	12646494	90	4 hour outage at Amica, Bldg 50 Sat 4/14/12 8:00AM start underground crew	DMAINT-G
LINCOLN	53-126W50	13576141	90	shutdown to replace main switch.precheck in docs.Oct 14th 7am will pay for crew	DMAINT-G
LINCOLN	53-126W50	7166269	90	785 GREAT RD - INSTALL STUB POLE AND GUY - TREE REMOVED THAT TREE GUY WASdm	DPUBLICRQ
LINCOLN	53-126W50	10879229	90	Bob 508-641-5936 dm poles	DPUBLICRQ
LINCOLN	53-126W50	11157307	90	Distribution Electric Public Requirement - Double Pole Project - Lincoln	DPUBLICRQ
LINCOLN	53-126W50	11169141	90	P 36-31 GREAT RD - NGRID TO REPLACE POLE & INST ANCHOR - INST GUY & TRANSFER	DPUBLICRQ
LINCOLN	53-126W50	11618963	90	Distribution Electric Public Requirement dm	DPUBLICRQ
LINCOLN	53-126W50	12301705	90	Distribution Electric Public Requirement dm SEE COMMENTS dm needs rock driller	DPUBLICRQ
LINCOLN	53-126W50	15148689	90	Replace tree guy with new stub pole -Distribution Electric Public Requirement ml	DPUBLICRQ
LINCOLN	53-126W50	25080304	80	Distribution Electric Public Requirement Teleco request 2/3HR dd 4/13	DPUBLICRQ
LINCOLN	53-126W50	21610330	90	Removal of pole & streetlight on customer's property. 2/4HRS	DPUBLICRQ
LINCOLN	53-126W50	30324335	80	Transfer to new pole	DPUBLICRQ
LINCOLN	53-126W50	30387788	90	Open & close 65K line fuses @ P.17-2 Jenckes Hill Rd, overhead 3-phase line tap	DPUBLICRQ
PROVIDENCE	53-126W50	5379593	90	RI Guy Survey, Feeder - 126W50 LINCOLN	DPUBLICRQ
WOONSOCKET	53-126W50	16617304	90	Distribution Electric Public Requirement	DPUBLICRQ
LINCOLN	53-126W50	3906641	90	INSTALL FAULT INDICATOR	DRELIABLE
LINCOLN	53-126W50	6121722	90	P.2 BREAKNECK HILL RD LINCOLN FY10 RECLOSER PROJECT clc	DRELIABLE
LINCOLN	53-126W50	6368822	90	Distribution Electric Reliability clc	DRELIABLE
LINCOLN	53-126W50	30619273	90	Distribution Electric Reliability	DRELIABLE

Pending Work

There are 8 open reliability work requests from 2022 and prior.

Twon	Feeder	WR Numb	WR Status	Work Request Description	Job Type
Lincoln	53-126W50	30541380	40	Remove XARMS from P.75 & P.76 after completion of bridge work by RIDOT	DENEDOT
LINCOLN	53-126W50	28308972	40	Replace urd street lights- rotted	DASSETREPL
LINCOLN	53-126W50	30530642	40	DOTR - BRIDGE GROUP 39 - BREAKNECK HILL ROAD BRIDGE - TEMP SWITCHES	DENEDOT
LINCOLN	53-126W50	27461130	50	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	30623257	50	Replace deteriorated transformer @ Pad 435-1 - 500kVA 480/277V SEE COMMENTS	DASSETREPL
Lincoln	53-126W50	30502843	60	DOTR - Twin River Rd Bridge over Rte 146 in Lincoln	DENEDOT
LINCOLN	53-126W50	30429998	60	UG Fault, 7/30/21, V 4-1, Fair Oaks Dr, Lincoln, RI, Fdr 126W50-Partial Complete	DCONFRMWO
LINCOLN	53-126W50	30654079	60	UG Fault, 9/2/22, Pole 14, Amica Center Blvd, Lincoln, RI., Fdr 126W50-Partial	DCONFRMWO

2023 Recommendations

These recommendations reflect both short-term projects and possible long-term improvements. There are independent load driven projects in planning for this circuit.

Title/Description	Category	Est. Cost	Storms WO	Status	Cust	Saved CM/Yr
Replace three 65K fuses with 65K Trip Savers at P74 Angell Road, Lincoln.	ERR	$16,376	30791518	Complete	304	3,500
At P8 Grandview Avenue, remove C/O and intall 40K TS looking toward P9 and 40Kfuse looking toward P7.	ERR	$12,000		Under Review	64	2,701
Install new PTR where main line feeds out of riser into ROW on the south side of Gearge Washington Highway. Install new pole just beyond P74 jfor the PTR. There have been more than 8 downline outages that have taken out the Amica complex. There is no reclosing on the station breaker. This would allow for reclose operations to adderss temporary downline faults.	ERR	$83,000		Under Review	1,612	100,000

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in Oct of 2018.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Pockets of animal outages were found on Grandview Ave and Sherman Ave in Lincoln. All issues are Grandview Ave have been addressed and no further improvements are required. The Sherman Ave location is to a single residence and the tap line and transformer are in the tree canopy. Animal related outages account for less than .6% of the outage minutes on this circuit over the last five years.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
Should the new recloser addition occur on P118 Nate Whipple Highway, load balancing will be incorporated at that time.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations (include Form3s):
See the recommendations above.

Additional Circuit Sectionalizing:
Not at this time.

Additional Feeder Ties/Reconfiguration:
No additional circuit ties are recommended at this time.

Protective Device Coordination Review:
Not necessary at this time.

Other Recommendations:
None

Rhode Island Energy™
a PPL company

Memorandum – CEMI and ERR – Feeder 53-126W50

To: Eric Wiesner

From: Mark Fraser

Date: July 17, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-126W50

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-126W50 feeder out of Washington Substation.

RELIABILITY PERFORMANCE

RIE System SAIFI				
2022	2021	2020	2019	2018
2.7	3.0	3.1	3.6	2.9

					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-126W50	9	1608	Mixed	11.04	96.6	311.3	294.5	372.1	165.3

RIE System SAIFI				
2022	2021	2020	2019	2018
2.7	3.0	3.1	3.6	2.9

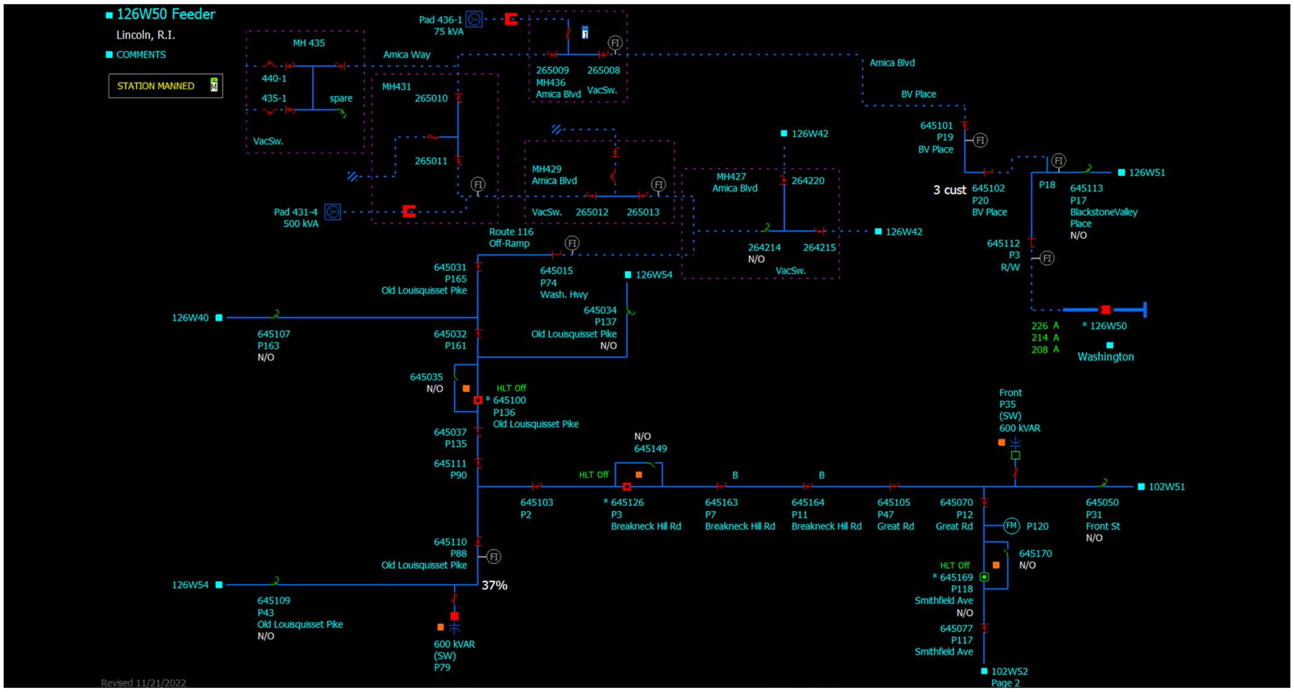
					CKAIDI Performance History				
Feeder	5 Year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018
53-126W50	9	1608	Mixed	11.04	0.99	6.90	4.35	6.88	1.62

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-126W50

Date	UNIQUE LOCATION	Cause	Day Type	Town	Estimated CKAIFI	Estimated CKAIDI Min
2/7/2020	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Major Storm	SMITHFIELD	2.991	1108.576
8/13/2018	53-126W50: D: BLACKSTONE VLY PL (0414)	Device Failed	Blue Sky	SMITHFIELD	2.532	63.044
5/15/2019	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	SMITHFIELD	1.009	1.009
2/3/2021	53-126W50: E: Road_not_found (0450)	Device Failed	Blue Sky	LINCOLN	1.007	28.623
11/1/2020	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	SMITHFIELD	1.007	31.212
8/12/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Fell	Blue Sky	LINCOLN	1.006	31.373
11/1/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Major Storm	LINCOLN	1.001	421.524
5/24/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Growth	Blue Sky	LINCOLN	1.001	146.690
10/11/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	LINCOLN	1.001	26.016
5/9/2020	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	SMITHFIELD	0.999	116.371
4/24/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Non-Company Activities	Blue Sky	LINCOLN	0.995	20.902
7/17/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree - Broken Limb	Blue Sky	SMITHFIELD	0.970	99.131
4/30/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Tree Fell	Blue Sky	SMITHFIELD	0.965	38.463
9/19/2021	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Animal	Blue Sky	SMITHFIELD	0.965	23.224
12/2/2019	53-126W50: A: WASHINGTON SUB (0156)	Unknown	Blue Sky	LINCOLN	0.964	30.846
9/8/2019	53-126W50: N: LOUISQUISSET FT11 PIKE (0125)	Unknown	Blue Sky	LINCOLN	0.958	66.082
3/2/2018	53-126W50: ODA: OLD JENKS HILL RD (0412)	Tree Fell	Major Storm	SMITHFIELD	0.659	887.262
5/8/2021	53-126W50: S: GREAT FT19 RD (0362)	Vehicle	Blue Sky	LINCOLN	0.502	9.627
3/16/2021	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Blue Sky	LINCOLN	0.502	0.502
8/4/2020	53-126W50: RK: GREAT FT19 RD (0362)	Tree Fell	Major Storm	LINCOLN	0.501	998.175
3/2/2018	53-126W50: S: GREAT FT19 RD (0362)	Tree Fell	Major Storm	LINCOLN	0.501	587.476
5/22/2022	53-126W50: S: GREAT FT19 RD (0362)	Vehicle	Blue Sky	LINCOLN	0.501	36.768
5/13/2019	53-126W50: S: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.501	22.641
10/7/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Lightning	Major Storm	LINCOLN	0.501	275.342
9/30/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Major Storm	LINCOLN	0.501	21.527
4/26/2020	53-126W50: R: BREAKNECK HILL RD (0081)	Tree - Broken Limb	Blue Sky	LINCOLN	0.501	17.021
10/30/2020	53-126W50: T: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.500	27.108
6/30/2021	53-126W50: T: GREAT FT19 RD (0362)	Tree Fell	Blue Sky	LINCOLN	0.499	22.591
8/19/2019	53-126W50: PAJMC: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.421	7.999
8/4/2020	53-126W50: PAJ: UNKNOWN86 ST (0154)	Tree - Broken Limb	Major Storm	SMITHFIELD	0.267	378.265
6/9/2021	53-126W50: PAJ: UNKNOWN86 ST (0154)	Tree Fell	Blue Sky	SMITHFIELD	0.230	23.010
9/18/2022	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.130	6.239
10/23/2018	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.127	38.440
2/25/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Major Storm	LINCOLN	0.123	21.807
8/23/2022	53-126W50: PAJL: ANGELL RD (0078)	Lightning	Blue Sky	LINCOLN	0.108	6.348
7/22/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.107	6.632
9/7/2019	53-126W50: PAJL: ANGELL RD (0078)	Tree - Broken Limb	Blue Sky	LINCOLN	0.106	7.550
8/16/2020	53-126W50: PAJL: ANGELL RD (0078)	Tree Fell	Blue Sky	LINCOLN	0.104	10.178
7/2/2022	53-126W50: V: WOODLAND ST (0411)	Tree Fell	Blue Sky	LINCOLN	0.089	30.325
8/4/2020	53-126W50: PD: JENCKES HILL RD (0110)	Unknown	Major Storm	LINCOLN	0.030	55.095
4/23/2023	53-126W50: V: WOODLAND ST (0411)	Tree Fell	Blue Sky	LINCOLN	0.090	18.090

One Line Map of the 126W50 Feeder



Completed Work

Over the last five years, 79 reliability Work Requests have been completed. These include addition of pole upgrades, transformer installations, capacitor bank additions, and fuse additions.

Twon	Feeder	WR Numb	WR Status	Work Request Description	Job Type
RI LINCOLN	53-126W50	15476221	90	126W50 priority D2M Computapole inspection WR for overhead.	DASSETOH2
LINCOLN	53-126W50	30438021	90	126W50 priority Level 9 Computapole inspection WR for overhead	DASSETOH2C
RI LINCOLN	53-126W50	15476220	90	126W50 priority D2C Computapole inspection WR for overhead - 521 locations.	DASSETOH2C
LINCOLN	53-126W50	346999	90	102W51 - Feeder Hardening - Condemned Pole	DASSETREPL
LINCOLN	53-126W50	3986358	90	Xarm Replacement	DASSETREPL
LINCOLN	53-126W50	3986367	90	Xarm Replacement	DASSETREPL
LINCOLN	53-126W50	8180359	90	Replace Cable & Xfmrs	DASSETREPL
LINCOLN	53-126W50	9344701	90	UPGRADE PAD TO 50 KVA	DASSETREPL
LINCOLN	53-126W50	11286454	90	126W50Telco replace P94 (40/3); upgrade XFMR (50kva); replace dnguy; transferdm	DASSETREPL
LINCOLN	53-126W50	12722969	90	126W50 Replace rusted minipad T3-10; Re-feed T1-7 dm SUGRUE	DASSETREPL
LINCOLN	53-126W50	12913997	90	126W50 P 80 TWIN RIVER RD -XFER ELEC TO TELCO REPLACED POLE	DASSETREPL
LINCOLN	53-126W50	13095520	90	126W50 VZ Pole replacement dm	DASSETREPL
LINCOLN	53-126W50	15191957	90	P9 ROCKY CLIFF DR-TRANSFER ELEC TO TELCO REPLACED POLE....POLE SET-YESdm	DASSETREPL
LINCOLN	53-126W50	15577140	90	Replace submersible xfmr w/minipad-Distribution Electric Asset Replacement ml	DASSETREPL
LINCOLN	53-126W50	16066894	90	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	19678699	90	Verizon has replaced P9 Angell Rd - 40'/2 Pole. Ngrid to transfer to new pole	DASSETREPL
LINCOLN	53-126W50	23185526	90	Distribution Electric Asset Replacement 4/4HRS	DASSETREPL
LINCOLN	53-126W50	23861333	90	Verizon replaced broken P4A1 622	DASSETREPL
LINCOLN	53-126W50	30315234	80	Replace direct buried cable with CIC via HDD method. Install CIC and new riser.	DASSETREPL
LINCOLN	53-126W50	23875873	90	Distribution Electric Asset Replacement 2/16 4 KIDS	DASSETREPL
LINCOLN	53-126W50	23875985	90	open wire replacement - P99-30 kids 2/hrs	DASSETREPL
LINCOLN	53-126W50	23883426	90	open wire replacement for: P1, 2, AND 3 kids 2 days	DASSETREPL
LINCOLN	53-126W50	26964694	90	UG switch replacement - Amica office park, Lincoln .89% EXPENSE 1/12/19	DASSETREPL
LINCOLN	53-126W50	27213457	90	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	27278422	90	Remove submersible switch & install OH & UG fault indicators 5.81% EXPENSE 622	DASSETREPL
LINCOLN	53-126W50	28331564	90	replace 25KVA W/ 50KVA, replace P71 & anchor W/ 40/3	DASSETREPL
LINCOLN	53-126W50	28677041	90	REPL P136 W/ 50' H1, REPL RECL W/ VIPER RECL Recls discontinued order	DASSETREPL
SMITHFIELD	53-126W50	28331260	90	Distribution Electric Asset Replacement - open wire dm	DASSETREPL
LINCOLN	53-126W50	22233433	90	7/11/2016, Pad 436, Amica Center Blvd, Lincoln RI, fdr #126W50.	DCONFRMWO
LINCOLN	53-126W50	23686884	90	Install 300' cable, 2/28/17, HH 3-1 - HH 3-5, Sylvia Dr, Lincoln, RI, Fdr 126W50	DCONFRMWO
LINCOLN	53-126W50	26849988	90	Replace vac. switch, 8/14/2018, MH 43 RI, Fdr. 126W50 9.55% EXPENSE	DCONFRMWO
LINCOLN	53-126W50	30492357	90	UG Fault, 11/10/21, Pad 1, Amica Center Blvd, Lincoln, RI., Fdr 126W50	DCONFRMWO
LINCOLN	53-126W50	30524751	90	1/4/22, Poles 8, 11, 15, Amica Center Blvd, Lincoln, RI, Fdr 126W50-Partial Comp	DCONFRMWO
LINCOLN	53-126W50	7748849	90	126W50 P9 ROCKY CLIFF RD - POLE SPLIT-TELCO TO REPLACE-TRANSFER NGRIDdm	DDAMAGE
LINCOLN	53-126W50	19811893	90	Replacement of 5 wood streetlight at the intersection of Dennell Dr & Lennon dm	DDAMAGE
LINCOLN	53-126W50	22768992	90	Distribution Electric Damage/Failure-N/B 2/4hrs good for apprentices	DDAMAGE
LINCOLN	53-126W50	30060858	80	Repl P.50-31 & remv 1/0 triplx P50-32 >P.50-33, verizon 2 remv p50-33	DDAMAGE
LINCOLN	53-126W50	23303994	90	Distribution Electric Damage/Failure-N/B 2/2hrs good for apprentices	DDAMAGE
LINCOLN	53-126W50	26390325	90	Replace rotted pole backyard kids BY mach 645	DDAMAGE
LINCOLN	53-126W50	26434228	90	Replace P131-30 (35/3); Telco remove old pole; transfer secondaries 2/4hr dd9/14	DDAMAGE
LINCOLN	53-126W50	28145326	90	Distribution Electric Damage/Failure-N/B 100%CAPEX KIDS/4H dd4/18	DDAMAGE
LINCOLN	53-126W50	28644545	90	REPL RECL SW# 645126. INST LB ON P3 SW#645150 PO4/4H EO 4/3.5D DD10/3	DDAMAGE
LINCOLN	53-126W50	30279253	90	Replace wood light pole with direct buired 14Ff tfiberglass pole, tradional head	DDAMAGE
LINCOLN	53-126W50	30350220	90	Replace handhole cover @ HH1-8 (closest to street light)	DDAMAGE
LINCOLN	53-126W50	30402045	80	DOTR - Bridge Group 39 - Break Neck Hill Road Bridge	DENEDOT
LINCOLN	53-126W50	857253	90	126W50 OLT dm	DLOADRELF
LINCOLN	53-126W50	2217191	90	OS FY08 TRANS OVERLOAD	DLOADRELF
LINCOLN	53-126W50	2217658	90	126W50 OS FY08 TRANS OVERLOAD dm	DLOADRELF
LINCOLN	53-126W50	16865903	90	Transformer change-out from a 25kva to a 50kva unit.	DLOADRELF
LINCOLN	53-126W50	30337880	80	OLT REPLC 2 XFMRS W/ 50KVA	DLOADRELF
LINCOLN	53-126W50	18946299	90	Installing new 50kva transfoerm on P5 Twin River Rd	DLOADRELF
LINCOLN	53-126W50	23073665	90	Distribution Electric Load Relief 4/8hrs -100%CAPEX	DLOADRELF
LINCOLN	53-126W50	25851946	90	Distribution Electric Load Relief - Install LVM on P120 VVO 4/8h dd 2/6	DLOADRELF
LINCOLN	53-126W50	25888804	90	Dist Elec Load Relief - Replace P35 and Intall Advance Cap Bank VVO 4/2D DD12/11	DLOADRELF
LINCOLN	53-126W50	25963297	90	Distribution Electric Load Relief - Repl Cap Bank with Smart VVO 4/12h	DLOADRELF
LINCOLN	53-126W50	27249210	90	Distribution Electric Load Relief, repl 50kva with 100kva padmount 4/3HR 100%cap	DLOADRELF
LINCOLN	53-126W50	29848486	90	Refuse LCO @ P.21 w/25K fuse. Replace LCO @ P.4 w/40K fuse.dm	DLOADRELF
LINCOLN	53-126W50	29850015	90	P.27 - transfer load to A-phase. P.42 - transfer load to A phase dm	DLOADRELF
LINCOLN	53-126W50	29850557	90	P.74 - change tap to C-phase, P.91 - transfer tap to A-phase dm	DLOADRELF
TIVERTON	53-126W50	22223433	90	Distribution Electric Load Relief OLT(1) 4/4h 645 23.76%EXP	DLOADRELF
LINCOLN	53-126W50	12646494	90	4 hour outage at Amica, Bldg 50 Sat 4/14/12 8:00AM start underground crew	DMAINT-G
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LINCOLN	53-126W50	11157307	90	Distribution Electric Public Requirement - Double Pole Project - Lincoln	DPUBLICRQ
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LINCOLN	53-126W50	12301705	90	Distribution Electric Public Requirement dm SEE COMMENTS dm needs rock driller	DPUBLICRQ
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LINCOLN	53-126W50	30324335	80	Transfer to new pole	DPUBLICRQ
LINCOLN	53-126W50	30387788	90	Open & close 65K line fuses @ P.17-2 Jenckes Hill Rd, overhead 3-phase line tap	DPUBLICRQ
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LINCOLN	53-126W50	6121722	90	P.2 BREAKNECK HILL RD LINCOLN FY10 RECLOSER PROJECT clc	DRELIABLE
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LINCOLN	53-126W50	30619273	90	Distribution Electric Reliability	DRELIABLE

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LINCOLN	53-126W50	28308972	40	Replace urd street lights- rotted	DASSETREPL
LINCOLN	53-126W50	30530642	40	DOTR - BRIDGE GROUP 39 - BREAKNECK HILL ROAD BRIDGE - TEMP SWITCHES	DENEDOT
LINCOLN	53-126W50	27461130	50	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W50	30623257	50	Replace deteriorated transformer @ Pad 435-1 - 500kVA 480/277V SEE COMMENTS	DASSETREPL
Lincoln	53-126W50	30502843	60	DOTR - Twin River Rd Bridge over Rte 146 in Lincoln	DENEDOT
LINCOLN	53-126W50	30429998	60	UG Fault, 7/30/21, V 4-1, Fair Oaks Dr, Lincoln, RI, Fdr 126W50-Partial Complete	DCONFRMWO
LINCOLN	53-126W50	30654079	60	UG Fault, 9/2/22, Pole 14, Amica Center Blvd, Lincoln, RI., Fdr 126W50-Partial	DCONFRMWO

2023 Recommendations

These recommendations reflect both short-term projects and possible long-term improvements. There are independent load driven projects in planning for this circuit.

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Replace three 65K fuses with 65K Trip Savers at P74 Angell Road, Lincoln.	ERR	$16,376	30791518	Complete	304	3,500
At P8 Grandview Avenue, remove C/O and intall 40K TS looking toward P9 and 40Kfuse looking toward P7.	ERR	$12,000		Under Review	64	2,701
Install new PTR where main line feeds out of riser into ROW on the south side of Gearge Washington Highway. Install new pole just beyond P74 jfor the PTR. There have been more than 8 downline outages that have taken out the Amica complex. There is no reclosing on the station breaker. This would allow for reclose operations to adderss temporary downline faults.	ERR	$83,000		Under Review	1,612	100,000

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in Oct of 2018.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Pockets of animal outages were found on Grandview Ave and Sherman Ave in Lincoln. All issues are Grandview Ave have been addressed and no further improvements are required. The Sherman Ave location is to a single residence and the tap line and transformer are in the tree canopy. Animal related outages account for less than .6% of the outage minutes on this circuit over the last five years.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
Should the new recloser addition occur on P118 Nate Whipple Highway, load balancing will be incorporated at that time.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations (include Form3s):
See the recommendations above.

Additional Circuit Sectionalizing:
Not at this time.

Additional Feeder Ties/Reconfiguration:
No additional circuit ties are recommended at this time.

Protective Device Coordination Review:
Not necessary at this time.

Other Recommendations:
None

Rhode Island Energy™
a PPL company

Memorandum – CEMI and ERR – Feeder 53-34F2

To: Eric Wiesner

From: Mark Fraser

Date: July 17, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-34F2

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-34F2 feeder out of Chopmist Substation.

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
Mark Fraser	No	53-34F2	1	2631	OH	21.94	141.2	214.0	187.2	282.5	285.2		

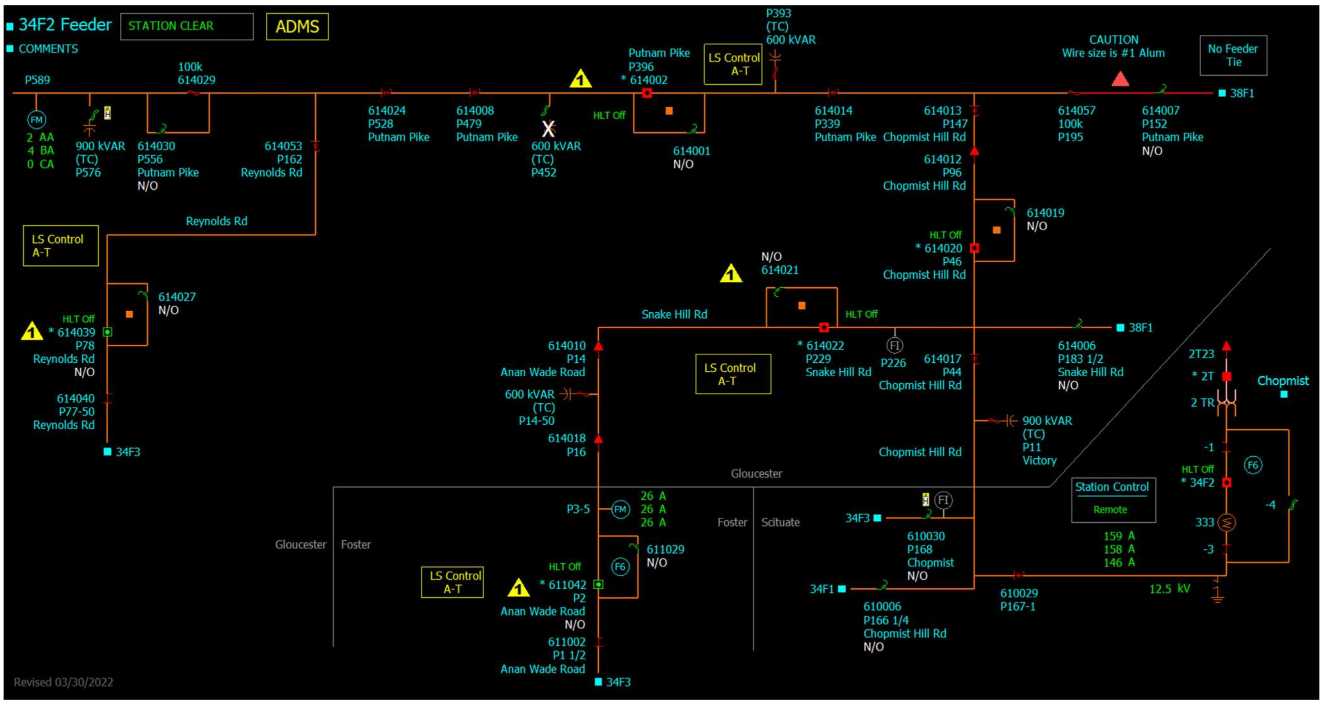
							CKAIFI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		53-34F2	1	2631	OH	21.94	2.20	1.19	0.94	1.84	1.01		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-34F2

Date	UNIQUE_LOCATION	Cause	DAY_TYPE	TWN_NAME	Estimated CKAIFI	Estimated CKAIDI Min
3/2/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Major Storm	LINCOLN	0.751	1442.422
8/4/2020	53-34F2: KCA: UNKNOWN8 ST (0575)	Tree Fell	Major Storm	GLOCESTER	0.251	604.702
3/7/2018	53-34F2: HR: PUTNAM PIKE (0585)	Unknown	Major Storm	GLOCESTER	0.288	391.574
7/28/2022	53-34F2: A: 2221 LINE RWAY (0132)	Device Failed	Blue Sky	SCITUATE	3.334	317.787
3/7/2018	53-34F2: CBHD: DURFEE HILL RD (0665)	Tree Fell	Major Storm	GLOCESTER	0.209	268.947
11/1/2019	53-34F2: J: PUTNAM PIKE (0585)	Tree Fell	Major Storm	GLOCESTER	0.291	231.457
8/4/2020	53-34F2: GP: MONEY HILL RD (0470)	Tree Fell	Major Storm	GLOCESTER	0.044	126.269
2/3/2023	53-34F2: GP: MONEY HILL RD (0470)	Device Failed	Blue Sky	GLOCESTER	0.477	121.986
9/30/2020	53-34F2: JE: REYNOLDS RD (0605)	Tree Fell	Major Storm	GLOCESTER	0.290	116.653
4/13/2020	53-34F2: CB: SNAKE HILL RD (0665)	Tree Fell	Major Storm	FOSTER	0.212	115.163
8/4/2020	53-34F2: EI: KEECH DAM RD (0765)	Device Failed	Major Storm	GLOCESTER	0.047	112.265
8/4/2020	53-34F2: CBHBB: CHESTNUT HILL RD (0120)	Device Failed	Major Storm	GLOCESTER	0.051	108.841
10/31/2019	53-34F2: FE: PUTNAM PIKE (0585)	Tree Fell	Major Storm	GLOCESTER	0.062	102.828
8/4/2020	53-34F2: HND: FIRST RD (0350)	Tree Fell	Major Storm	GLOCESTER	0.040	102.495
4/13/2020	53-34F2: HN: JACKSON SCHOOL HSE RD (0585)	Tree Fell	Major Storm	GLOCESTER	0.061	98.700
3/2/2018	53-34F2: EI: KEECH DAM RD (0765)	Tree - Broken Limb	Major Storm	GLOCESTER	0.047	92.472
11/1/2019	53-34F2: EI: KEECH DAM RD (0765)	Unknown	Major Storm	GLOCESTER	0.047	88.134
8/4/2020	53-34F2: CBHBC: CHESTNUT HILL RD (0120)	Device Failed	Major Storm	GLOCESTER	0.035	84.097
3/7/2018	53-34F2: FE: PUTNAM PIKE (0585)	Tree Fell	Major Storm	GLOCESTER	0.060	78.415
8/22/2021	53-34F2: CBHD: DURFEE HILL RD (0665)	Tree Fell	Major Storm	GLOCESTER	0.051	74.310
8/4/2020	53-34F2: EE: VICTORY HWY (0765)	Device Failed	Major Storm	GLOCESTER	0.031	73.857
5/23/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	FOSTER	1.055	61.834
12/21/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree Fell	Blue Sky	GLOCESTER	0.452	58.433
1/20/2019	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.266	57.018
10/31/2019	53-34F2: CBH: SNAKE HILL RD (0665)	Unknown	Major Storm	FOSTER	0.042	56.829
10/27/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.742	53.591
1/24/2019	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.454	40.599
3/16/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.384	39.508
10/27/2021	53-34F2: FE: PUTNAM PIKE (0585)	Tree Fell	Major Storm	GLOCESTER	0.052	34.828
12/17/2019	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	LINCOLN	0.412	32.237
1/20/2019	53-34F2: CB: SNAKE HILL RD (0665)	Tree - Broken Limb	Blue Sky	FOSTER	0.202	32.208
2/3/2023	53-34F2: CBHBBK: BROWN SCHOOL RD (0120)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.028	31.443
2/25/2019	53-34F2: HP: PUTNAM PIKE (0585)	Tree - Broken Limb	Major Storm	GLOCESTER	0.024	31.273
3/18/2021	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.763	28.209
9/12/2018	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	LINCOLN	0.450	28.128
10/14/2021	53-34F2: CB: SNAKE HILL RD (0665)	Vehicle	Blue Sky	GLOCESTER	0.205	27.792
12/11/2021	53-34F2: CBH: SNAKE HILL RD (0665)	Tree Fell	Blue Sky	GLOCESTER	0.151	27.280
8/16/2020	53-34F2: GK: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	LINCOLN	0.461	25.122
4/15/2019	53-34F2: CB: SNAKE HILL RD (0665)	Tree - Broken Limb	Major Storm	GLOCESTER	0.210	23.541
9/3/2019	53-34F2: A: 2221 LINE RWAY (0132)	Unknown	Blue Sky	LINCOLN	1.464	19.341
2/12/2022	53-34F2: I: PUTNAM PIKE (0585)	Vehicle	Blue Sky	GLOCESTER	0.288	18.930
2/25/2019	53-34F2: CB: SNAKE HILL RD (0665)	Tree - Broken Limb	Major Storm	FOSTER	0.201	17.727
10/31/2020	53-34F2: H: PUTNAM PIKE (0585)	Device Failed	Blue Sky	GLOCESTER	0.358	17.344
1/6/2019	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	LINCOLN	0.453	15.596
3/1/2021	53-34F2: H: PUTNAM PIKE (0585)	Tree Fell	Blue Sky	GLOCESTER	0.290	13.630
10/22/2020	53-34F2: CB: SNAKE HILL RD (0665)	Tree Fell	Blue Sky	GLOCESTER	0.167	13.345
4/3/2020	53-34F2: H: PUTNAM PIKE (0585)	Tree - Broken Limb	Blue Sky	GLOCESTER	0.291	12.519

One Line Map of the 34F2 Feeder



Completed Work

Over the last five years, 52 reliability Work Requests have been completed. These include addition of crossarm mounted reclosers, pole upgrades, transformer installations, capacitor bank additions, and fuse additions.

Town	Feeder	WR Number	Status	Work Request Description	Job Type
GLOCESTER	53-34F2	26716432	90	34F2 priority D2C Computapole inspection WR for overhead - 2 locations.	DASSETOH2C
GLOCESTER	53-34F2	30325355	80	Poles and anch exist in field. Transfer facilities on 3 poles	DASSETREPL
GLOCESTER	53-34F2	30325372	80	Teleco Previously repalced pole.Trransfer facilities, install 50KVA,remove 25KVA	DASSETREPL
GLOCESTER	53-34F2	30738196	80	I&M Level 9 Computapole	DASSETREPL
GLOCESTER	53-34F2	30738217	80	I&M Level 9 Computapole	DASSETREPL
GLOCESTER	53-34F2	30742043	80	I&M Level 9 Computapole - 1ph pole & anchor replacement	DASSETREPL
GLOCESTER	53-34F2	30748224	80	Distribution Electric Asset Replacement	DASSETREPL
GLOCESTER	53-34F2	23842955	90	Distribution Electric Asset Replacement OPEN WIRE kids/4h 19.67%EXP	DASSETREPL
GLOCESTER	53-34F2	25699953	90	REPLACE ROTTED P9 // REM 4KV 25KVA-INST 10KVA DUAL P16 S. ATLANTIC dm	DASSETREPL
GLOCESTER	53-34F2	30024678	90	REPLACE TREE GUY W/ DOW GUY @ P99 DETAIL- D/S-1 CREW 4 HRS	DASSETREPL
GLOCESTER	53-34F2	30318602	90	RELOCATE POLE 368-1 & ASSOCIATED EQUIP APRRX 15' NE	DASSETREPL
GLOCESTER	53-34F2	30323058	90	TRANSFER FACILITIES TO NEW POLE 353	DASSETREPL
GLOCESTER	53-34F2	30325153	90	Transfer attachements to newly replaced P.1,	DASSETREPL
GLOCESTER	53-34F2	30325158	90	transfer attachements to replaced pole 43	DASSETREPL
GLOCESTER	53-34F2	30325518	90	TRANSFER FACILITIES @ P2	DASSETREPL
GLOCESTER	53-34F2	29740495	90	Repl Pole, 5/8/20, Pole 14-1, Safari Rd, Glocester, RI, Fdr#34F2	DCONFRMWO
GLOCESTER	53-34F2	29751328	90	Replaced Pole, 5/13/20, Pole 17, S. Atlantic Ave, Glocester, RI, Fdr#34F2	DCONFRMWO
GLOCESTER	53-34F2	30283980	90	Cable Fault, 11/17/20, Rustic Acre Dr, Glocester, RI, Fdr#34F2	DCONFRMWO
GLOCESTER	53-34F2	26253112	90	INST NEW P6 1/2 ATTACH PRIM & SEC REPL SERV SPAN IN TREE 4/4h dd3/9 7.4%EXP	DDAMAGE
GLOCESTER	53-34F2	29120543	90	install anchor @ P.16-3 remove existing down guy wire to tree stump. 2/4h DD12/9	DDAMAGE
GLOCESTER	53-34F2	30048554	90	REPL BURNT P60 W/ 40' C/2 SAME HOLE & OLT W/ 25KVA DETAIL D/S	DDAMAGE
SCITUATE	53-34F2	27678266	90	REPL P177-1 REM TREEGUYS P177-1 & 177-2 ANCH PO2/8H637 EO4/4HDD5/17 10.14%EXP	DDAMAGE
CHEPACHET	53-34F2	26813299	90	UPGRADE 10KVA @ P.137 TO 25KVA - OVERLOADED 4/3H	DLOADRELF
FOSTER	53-34F2	30422374	90	DER Chopmist - 34F2 - P3-50 LVM	DLOADRELF
GLOCESTER	53-34F2	30423220	90	DER Chopmist - 34F2 - P589 LVM	DLOADRELF
GLOCESTER	53-34F2	30645013	80	EXPEDITED DESIGN DG job Distributed Generation Projects	DPUBLICDG
CHEPACHET	53-34F2	30286740	90	REPL P105, INST 50KVA, NETCUT P106, DEDICATE 50KVA @ P106 TO HSE #243	DPUBLICDG
GLOCESTER	53-34F2	29010900	80	remove tree guy & install secondary down guy & anchor @ P.4 2/2h dd1/9	DPUBLICRQ
CHEPACHET	53-34F2	24999093	90	Distribution Electric Public Requirement 2/4HRS DD1/8	DPUBLICRQ
CHEPACHET	53-34F2	29983613	90	REPLACE P438-3, DOWN GUY, 25KVA XFOMER	DPUBLICRQ
CHEPACHET	53-34F2	30142467	90	Distribution Electric Public Requirement	DPUBLICRQ
CHEPACHET	53-34F2	30565782	90	REPL TREE GUY W/ DOWN GUY & POLE # 2 W/ 40' C/2	DPUBLICRQ
GLOCESTER	53-34F2	21321925	90	Distribution Electric Public Requirement 2/3hrs	DPUBLICRQ
GLOCESTER	53-34F2	24766727	90	Distribution Electric Public Requirement 2/2hrs DD 2/5	DPUBLICRQ
GLOCESTER	53-34F2	25766796	90	6 POLES PRI DR 7 ANCH 1,092 ' PRI /NEUT 130 ' SEC po 2/3d DD10/16 0.36%EXP	DPUBLICRQ
GLOCESTER	53-34F2	26519052	90	REM P/T GUY & INST SIDEWALK ANCH GUY - TO REM TREE 2/4h dd 8/31	DPUBLICRQ
GLOCESTER	53-34F2	26548226	90	REM POLE TO TREE GUY & INST SIDEWALK-ANCHOR GUY 2/4H dd8/14 1.42%EXP	DPUBLICRQ
GLOCESTER	53-34F2	26792098	90	iNST(1") anc & DOWN GUY @ P.4-1 REMOVE P/T GUY PRIVPROP 0.88%exp 2/4h dd9/24	DPUBLICRQ
GLOCESTER	53-34F2	27664409	90	Dist Elect Pub Req po2/2h eo4/2h dd7/1 100%CAPEX DISABLED VET WAITING FOR THIS	DPUBLICRQ
GLOCESTER	53-34F2	28495866	90	Reloc P.6-2 to prop line, inst 1/0 triplex P.5 to P.6 and inst net 4/16h dd3/5	DPUBLICRQ
GLOCESTER	53-34F2	29169398	90	Repl 235ft of 1/0 nuetral w/1/0 triplex connect cust owned street light kid/8h	DPUBLICRQ
GLOCESTER	53-34F2	30047592	90	REMV TREE GUY, RELOCATE P10-2, INST DOWN GUY & NEW SVC DROP	DPUBLICRQ
GLOCESTER	53-34F2	30302809	90	RELOCATE P1 APPRX 27' NORTH - NEW 40' C/2 P1 + GUY	DPUBLICRQ
GLOCESTER	53-34F2	30399872	90	Distribution Electric Public Requirement	DPUBLICRQ
GLOCESTER	53-34F2	30571562	90	Distribution Electric Public Requirement	DPUBLICRQ
GLOCESTER	53-34F2	23553532	90	Distribution Electric Reliability 4/8hrs DD 1/23	DRELIABLE
GLOCESTER	53-34F2	25047553	90	Distribution Electric Reliability 4/4HRS DD 1/8/18	DRELIABLE
GLOCESTER	53-34F2	25712021	90	REFUSE FUSE C/O (L) / REM 65K, INST 100K 4/3HRS 100%CAPEX	DRELIABLE
GLOCESTER	53-34F2	27067934	90	INSTALL RADIO RECLOSER CONTROL	DRELIABLE
GLOCESTER	53-34F2	28244237	90	REPL 40K FUSE W/ 65K CMR P16, REPL BOTH 65K FUSE W/ 100K FUSE ON P3 4/3h dd8/14	DRELIABLE
GLOCESTER	53-34F2	29558061	90	REPL FUSE ON P439 PUTNAM PK. W/ CMR dm	DRELIABLE
GLOCESTER	53-34F2	29748702	90	REPL 2PH CONST W/ 1PH BTW P2 - P6 ON ROW OFF RUSTIC HILL RD.dm	DRELIABLE

Pending Work

There are 13 open reliability work requests from 2022 and prior mainly related to capacitor installations and a new recloser.

Town	Feeder	WR Number	Status	Work Request Description	Job Type
RI GLOCESTER	53-34F2	29952133	10	34F2 priority D2C Computapole inspection WR for overhead - 179 locations.	DASSETOH2C
GLOCESTER	53-34F2	30427114	20	DER Chopmist - 34F2 - P 576 CAP	DLOADRELF
GLOCESTER	53-34F2	30427121	20	DER Chopmist - 34F2 - P452 CAP	DLOADRELF
GLOCESTER	53-34F2	30427124	20	DER Chopmist - 34F2 - P393 CAP	DLOADRELF
GLOCESTER	53-34F2	30444722	20	DER Chopmist - 34F2 - P16 CAP BANK	DLOADRELF
GLOCESTER	53-34F2	30444790	20	DER Chopmist - 34F2 - New P151 Recloser	DLOADRELF
GLOCESTER	53-34F2	30445165	20	DER Chopmist - 34F2 - P11 Cap Bank	DLOADRELF
GLOCESTER	53-34F2	30594538	40	Distribution Electric Public Requirement	DPUBLICRQ
NORTH SCITUATE	53-34F2	30726202	40	Distribution Electric Public Requirements for Distributed Generation Projects	DPUBLICDG
GLOCESTER	53-34F2	29291762	50	REPL P12 ON ROW BEHIND PROP # 117 SPRING GROVE dm	DRELIABLE
GLOCESTER	53-34F2	30755265	50	I&M Level 9 Computapole - 1ph pole	DASSETREPL
GLOCESTER	53-34F2	30703563	60	ASSET REPLACEMENT 12/05/22, 1615 SNAKE HILL RD, N. SCITUATE RI FDR 34F2	DASSETREPL
RI GLOCESTER	53-34F2	17134667	60	34F2 priority D2C Computapole inspection WR for overhead - VZ locations.	DASSETOH2C

2023 Recommendations

These recommendations reflect both short-term projects and possible long-term improvements. Many of the projects are either completed or under consideration.

Title/Description	Category	Est. Cost	Storms WO	Status	Cust	Est. Saved CM/Yr
Replace the 65K fuse at P97 Victory Highway with a 100K CMR feeding down Keach Dam Road. Glouster.	ERR		30791593	Complete	128	3,072
Install 2-65K fuses at P451 Putnam Pike feeding down Jackson School House Road. Replace 25K fuse with a 40K CMR at P5-50 Jackson School House Road feeding First Road. Glocester.	ERR		30791593	Complete	109	2,616
Replace 65K fuse with a 65K CMR at P99-50 Chestnut Hill Road, Glocester.	ERR		30791593	Complete	92	2,208
Replace existing 100K fuse with a 100K CMR at P283 Snake Hill Road feeding Durfee Hill Road, Glocester.	ERR		30791593	Complete	131	3,851
Replace existing 40K fuse with a 40K CMR at P204 Putnam Pike feeding Tourtelotte Hill Road, Glocester.	ERR		30791593	Complete	66	1,584
		$39,542		Complete		
Install new PTR at P339 Putnam Turnpike. This would break up circuit while separating Putnum Pike from Chopmist Hill Road where most of the faults occur.	ERR	$83,000		Under Review	537	47,252
Install new Tie PTR on Snake Hill Road on the west side of P183-50 LBS 614006.	ERR	$83,000		Under Review	816	19,584

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in July of 2021.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Over the five-year period, there were 406 customers impacted by animal related outages accounting for 45,491 customer minutes interrupted. This equates to .26% of all customer outage minutes during that period. No specific recommendations are being proposed.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
This is not being considered at this time.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations (include Form3s):
See the recommendations above.

Additional Circuit Sectionalizing:
See the recommendations above.

Additional Feeder Ties/Reconfiguration:
No additional feeder ties are suggested at this time.

Protective Device Coordination Review:
Not necessary at this time.

Other Recommendations:
None

Memorandum – CEMI and ERR – Feeder 53-126W51

To: Eric Wiesner

From: Mark Fraser

Date: July 19, 2023

Subject: Problem and Poor Performing Reliability Review for feeder 53-126W51

This memo documents the recommendations to improve CKAIFI and CKAIDI on the 2022 Poor Performing 53-126W51 feeder out of Washington Substation.

RELIABILITY PERFORMANCE

							CKAIDI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIDI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022* Min	2021 Min	2020 Min	2019 Min	2018 Min	Short Term Work	Long Term Work
Mark Fraser	No	53-126W51	15	1748	OH	7.45	54.2	127.0	198.4	132.6	150.3		

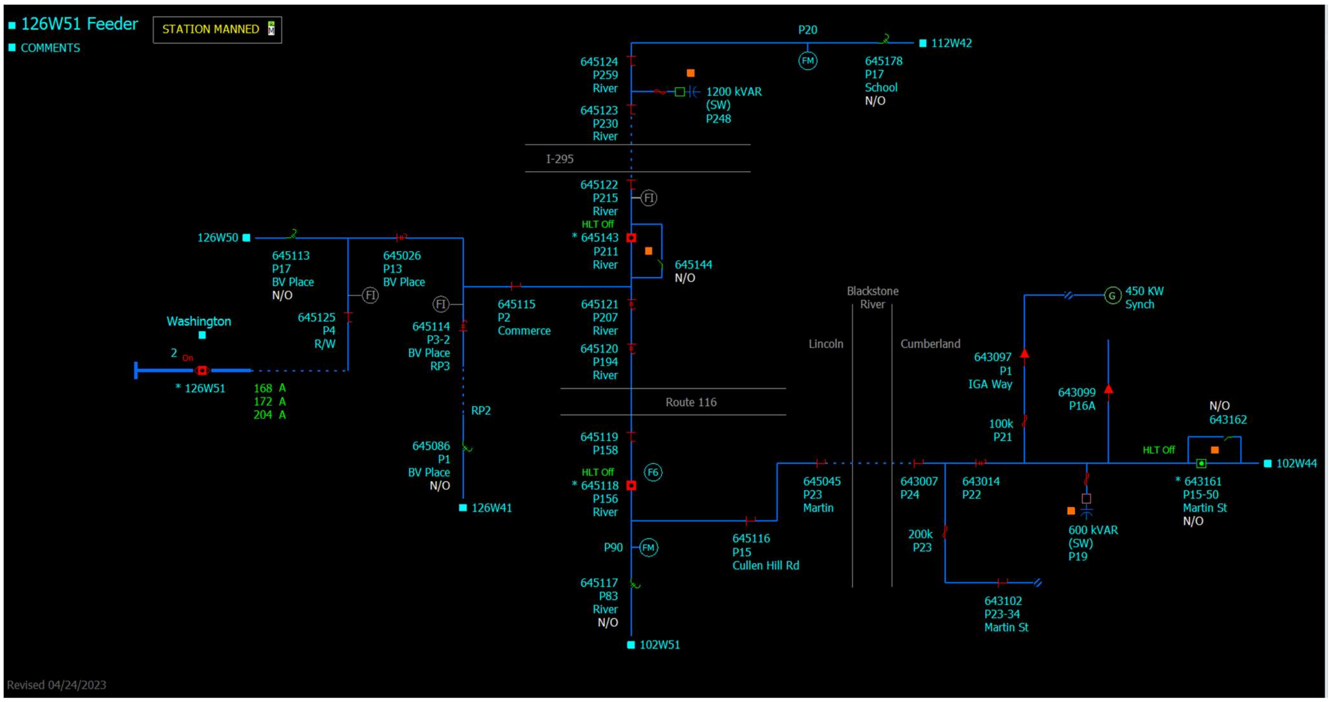
							CKAIFI Performance History					Improvements	
Engineer	CEMI 4 Circuit	CKAIFI Feeder	5 year Combined CI and CMI rank	Cust. Served	Const_ Type	3 Ph OH Line Miles	2022	2021	2020	2019	2018	Short Term Work	Long Term Work
		53-126W51	15	1748	OH	7.45	1.70	2.10	2.16	2.89	2.65		

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit 53-126W51

Date	Unique Location	Cause	Day Type	Town	Estimated CKAIFI	Estimated CKAIDI Min
1/17/2020	53-126W51: CG: BLACKSTONE VLY PL (0414)	Tree Fell	Blue Sky	CUMBERLAND	3.586	300.855
7/2/2022	53-126W51: A: WASHINGTON SUB (0156)	Lightning	Blue Sky	LINCOLN	1.428	40.174
12/1/2019	53-126W51: A: WASHINGTON SUB (0156)	Insulation failure - cable	Blue Sky	CUMBERLAND	1.411	47.339
3/14/2020	53-126W51: A: WASHINGTON SUB (0156)	Tree - Broken Limb	Blue Sky	LINCOLN	1.410	57.805
8/23/2019	53-126W51: CG: BLACKSTONE VLY PL (0414)	Tree Fell	Blue Sky	LINCOLN	1.406	69.835
9/13/2018	53-126W51: A: WASHINGTON SUB (0156)	Tree - Broken Limb	Blue Sky	CUMBERLAND	1.403	176.830
8/19/2021	53-126W51: DBBA: RIVER FT4 RD (0028)	Tree Fell	Blue Sky	CUMBERLAND	1.401	41.195
1/5/2023	53-126W51: A: WASHINGTON SUB (0156)	Vehicle	Blue Sky	CUMBERLAND	0.991	17.444
2/26/2022	53-126W51: H: RIVER FT11 RD (0141)	Tree - Broken Limb	Blue Sky	LINCOLN	0.820	28.713
8/4/2020	53-126W51: HF: DUCARL DR (0328)	Unknown	Major Storm	CUMBERLAND	0.815	510.165
3/29/2021	53-126W51: H: RIVER FT11 RD (0141)	Tree - Broken Limb	Blue Sky	CUMBERLAND	0.815	32.609
10/9/2019	53-126W51: H: RIVER FT11 RD (0141)	Tree - Broken Limb	Blue Sky	LINCOLN	0.812	29.224
9/13/2018	53-126W51: H: RIVER FT11 RD (0141)	Unknown	Blue Sky	CUMBERLAND	0.807	16.825
11/1/2019	53-126W51: H: RIVER FT11 RD (0141)	Tree - Broken Limb	Major Storm	CUMBERLAND	0.806	120.769
3/13/2018	53-126W51: HK: RIVER FT12 RD (0328)	Tree Fell	Major Storm	CUMBERLAND	0.805	235.473
3/2/2018	53-126W51: DBBAG: RIVER FT4 RD (0028)	Unknown	Major Storm	LINCOLN	0.525	287.229
2/25/2019	53-126W51: DB: RIVER FT4 RD (0028)	Device Failed	Major Storm	LINCOLN	0.503	19.591
2/4/2023	53-126W51: H: RIVER FT11 RD (0141)	Device Failed	Blue Sky	LINCOLN	0.388	25.312
11/1/2021	53-126W51: DBBAG: RIVER FT4 RD (0028)	Unknown	Blue Sky	LINCOLN	0.154	24.007
11/2/2021	53-126W51: DBBAG: RIVER FT4 RD (0028)	Animal	Blue Sky	LINCOLN	0.149	7.466
2/1/2021	53-126W51: DBBAG: RIVER FT4 RD (0028)	Unknown	Blue Sky	LINCOLN	0.145	11.189
7/17/2021	53-126W51: HC: SIMON SAYLES RD (0141)	Tree Fell	Blue Sky	LINCOLN	0.130	39.868
7/21/2019	53-126W51: HC: SIMON SAYLES RD (0141)	Device Failed	Blue Sky	LINCOLN	0.105	7.328
3/2/2018	53-126W51: HC: SIMON SAYLES RD (0141)	Unknown	Major Storm	LINCOLN	0.101	106.627
3/2/2018	53-126W51: HF: DUCARL DR (0328)	Tree Fell	Major Storm	LINCOLN	0.034	42.341

One Line Map of the 126W51 Feeder



Completed Work

Over the last five years, 28 reliability Work Requests have been completed. These include the addition of crossarm mounted reclosers, pole upgrades, tie recloser installation, capacitor bank upgrade, and fuse additions

City/Town Desc	Feeder Number	WR Number	WR Status Code	Work Request Description	Job Type Code
LINCOLN	53-126W51	29390117	90	126W51 priority Level 9 Computapole inspection WR for overhead - 1 loc 622 645	DASSETOH2C
LINCOLN	53-126W51	29398927	90	126W51 priority Level 9 Computapole insp WR for oh- 3 locations. KIDS 8/H dd1/22	DASSETOH2C
LINCOLN	53-126W51	29403898	90	126W51 priority Level 9 Computapole inspection WR for overhead - 1 locations.dm	DASSETOH2C
LINCOLN	53-126W51	29408936	90	126W51 priority Level 9 insp WR for overhead - 1 locations.4/8h dd2/27	DASSETOH2C
LINCOLN	53-126W51	26151224	90	Distribution Electric Asset Replacement 4/8h dd3/6	DASSETREPL
LINCOLN	53-126W51	27036855	90	Replace three rotted poles transfer 1ph & secondary kids/4D renew ds	DASSETREPL
LINCOLN	53-126W51	29212081	90	Distribution Electric Asset Replacement	DASSETREPL
LINCOLN	53-126W51	30566627	90	Pad 4-34 - Replace pad mounted transfomrer 300 KVA,208/120V, replace primary	DASSETREPL
LINCOLN	53-126W51	29309299	90	Cable Fault, 12/1/19, 642 George Washington Hwy, Lincoln RI, Fdr#126W51	DCONFRMWO
LINCOLN	53-126W51	27131158	90	Replace rotted pole 4/8H DD12/28	DDAMAGE
LINCOLN	53-126W51	29870076	90	Replace P.23 w/40t cl-3 JO pole, & @ P.24 replace 25kVA w/50kVA...	DDAMAGE
LINCOLN	53-126W51	29926546	90	Replace P.109 & P.111 Old River Rd D/S	DDAMAGE
LINCOLN	53-126W51	30105631	90	Replace P.100 Old River Rd	DDAMAGE
LINCOLN	53-126W51	30425760	90	Replace P.51 w/45ft cl-2 5E pole.	DDAMAGE
LINCOLN	53-126W51	30441852	90	Replace P.5 w/40ft cl-3 JO pole.	DDAMAGE
CUMBERLAND	53-126W51	25963314	90	RI Volt Var: Repl Cap Bank P19 w/smart controls VVO 4/12H	DLOADRELF
LINCOLN	53-126W51	25839431	90	Distribution Electric Load Relief - Replace Cap Bank on P248 VVO 4/2D 7.27%EXP	DLOADRELF
LINCOLN	53-126W51	25846894	90	Volt Var RI - Install LVM on P20 School St VVO 4/8h dd2/12	DLOADRELF
LINCOLN	53-126W51	25877873	90	Install LVM on P21 River Rd 4/2D 645 dd2/25 FAA	DLOADRELF
LINCOLN	53-126W51	30386188	90	Replace O/L transformer	DLOADRELF
LINCOLN	53-126W51	30603662	80	Open LB @ P.83 and close LB @ P.14 per Planning Dept	DLOADRELF
LINCOLN	53-126W51	30621179	90	Distribution Electric Public Requirements for Distributed Generation Projects	DPUBLICDG
LINCOLN	53-126W51	27614471	90	Distribution Electric Public Requirement	DPUBLICRQ
LINCOLN	53-126W51	29566412	80	Remove tree guy @ P.30 School St, install SO guy pole w/anchor.dm KIDDIES	DPUBLICRQ
CUMBERLAND	53-126W51	30624448	80	Recloser Feeder Tie Install 126W51/102W44- Viper 6IVS	DRELIABLE
LINCOLN	53-126W51	27071285	90	INSTALL RADIO RECLOSER CONTROL	DRELIABLE
LINCOLN	53-126W51	29235133	90	Replace cutout w/ 65K Cutout Mounted Recloser * DM, AL, JA see me before closing	DRELIABLE
LINCOLN	53-126W51	30471169	90	Install 2-25K line fuses @ P.20 Oak Hill Dr tap, & Tinberland Dr	DRELIABLE

Pending Work

There are 2 open reliability work requests from 2022 and prior. One is related to a pole replacement and the other is an overhead inspection job.

2023 Recommendations

This circuit was last on the ERR List in 2019. Improvements were made at that time. There are 4 main line reclosers and some circuit adjustments in progress on this circuit. The recommendations relate primarily to short term improvements.

Title/Description	Category	Est. Cost	Storms WO	Status	Customers Served	Est. Customer Min Saved
At P123 Great Road, moved the tap toward P122 from Phase C (Middle) to Phase A (botton). Lincoln	ERR	$500			59	
Replace 40K fuse at P122 Grear Road with a 65K CMR. Lincoln	ERR	$10,000			59	1,416
Replace 3- 40K fuses at P130 with 3-65K fuses. Lincoln	ERR	$1,500			200	
Replace 25K fuse at P1 Wilbur Road with a 40K CMR looking toward yP148 Great Road and add a C/O with a 40K fuse looking toward P2 Wilbur Road. Lincoln	ERR	$12,000			94	2,256
Add a C/O with 25K fuse at P12 Kirkbrae Drive looking toward P13 Kirkbrae Drive. Lincoln	ERR	$1,000			111	1,332
Add a C/O with 25K fuse at P3 Tiberland Drive looking toward P21 Kirkbrae Drive. Lincoln	ERR	$1,000			113	1,356
Replace 40K fuse at P2 Kennedy Blvd with a 65K CMR looking left toward P3 Kennedy Blvd and add a C/O with a 65K fuse looking right toward P1 Pine Grove Ave. Lincoln	ERR	$12,000			104	1,058
Replace 25K fuse at P25 Kennedy Blvd with a 40K fuse. Lincoln	ERR	$500			46	

General Recommendations:

Tree Trimming:
Maintenance and Enhanced Tree Trimming was completed on the circuit in March of 2022.

Infrared Circuit Scan:
All circuits on the ERR and CEMI list are to be Infrared Surveyed in 2023/24

Animal Mitigation:
Outages caused by animal contacts were a very small percentage of the outage minutes for this circuit. No additional measures are recommended.

Fault Indicators:
No additional fault indicators have been requested.

Load Balancing:
Load balancing is not required at this time.

Cutout Mounted Recloser Installations:
See the recommendations above.

Line Recloser Installations (include Form3s):
There are four mainline reclosers on this feeder.

Additional Circuit Sectionalizing:
No additional sectionalizing is recommended at this time.

Additional Feeder Ties/Reconfiguration:
No additional circuit ties are recommended at this time.

Protective Device Coordination Review:
Not necessary at this time.

Other Recommendations:
None

Division 4-14
CEMI-4, ERR and Distribution Automation – Various

Request:

Provide a list of each circuit proposed for work under the ERR program in FY 2025. For each circuit, provide information comparable to pp. 155-156 including reliability performance, one-line, and summary of all outage events over the last five years.

Response:

The performance data, one-lines, and outage summaries are attached:

Attachment DIV 4-14-1 - 2025 ERR Circuit List with Performance Data
Attachment DIV 4-14-2 - ERR Circuit One-lines
Attachment DIV 4-14-3 - Five-Year Outage Summary for ERR Circuits as Excel file

Please note that the format of the information on Pages 155-156 is part of the ERR Memorandum document that is completed as part of the circuit review. The reviews are to be finished by the end of December and have not been written at this time.

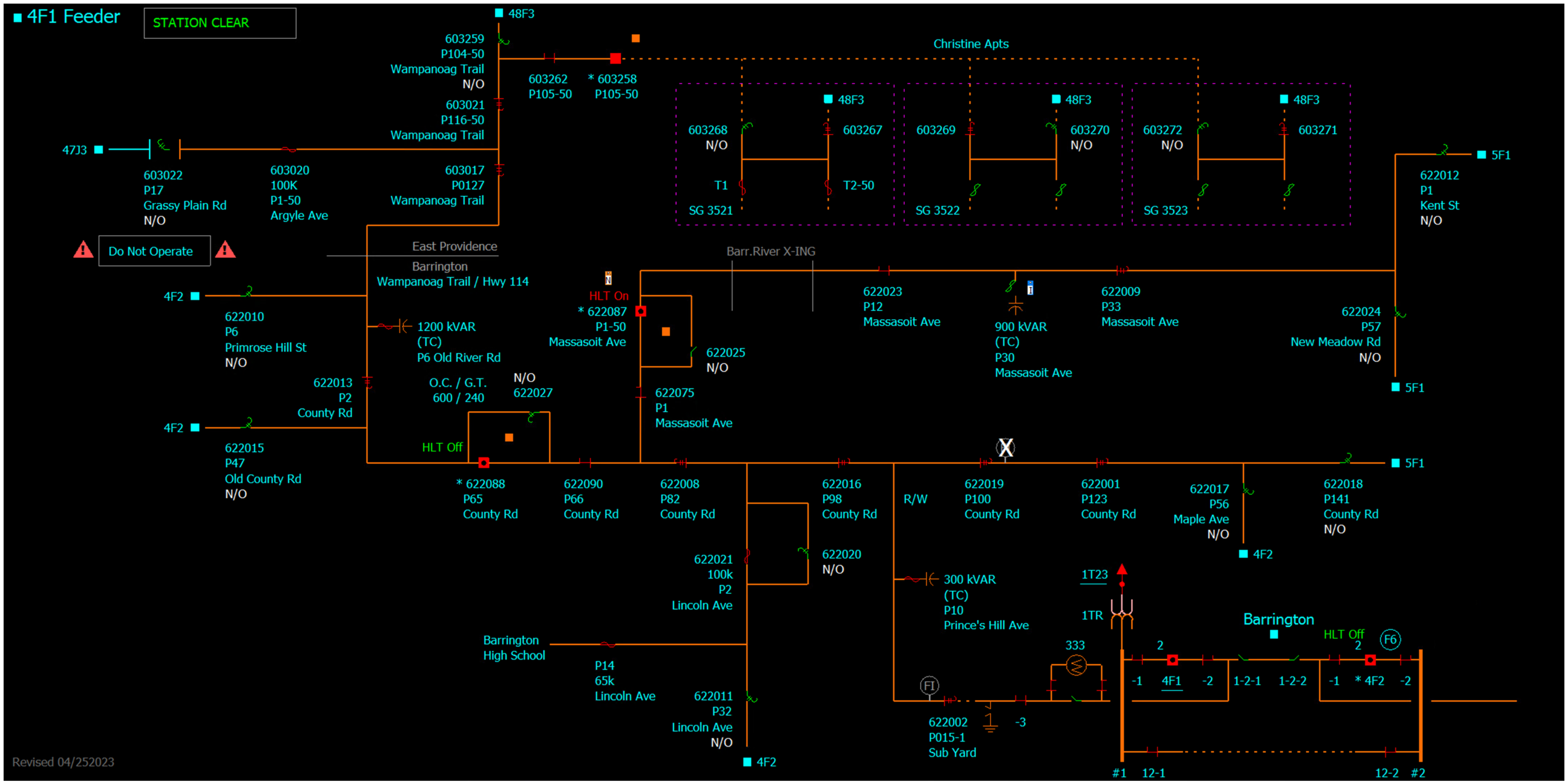
Prepared by or under the supervision of: Ryan Constable and Eric Wiesner

DIV 4-14-1
5 year ERR Circuit Performance Data

Substation	Circuit	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	Maximum Duration (min)
W. Greenville	53-45F2	27	4,401	300,289	1,867	2.36	160.84	68.23	1,165
West Cranston	53-21F1	18	4,167	350,307	2,521	1.65	138.96	84.07	1,424
Dexter	56-36W44	12	3,936	304,230	2,177	1.81	139.75	77.30	827
Chase Hill	56-155F2	20	3,917	292,823	1,311	2.99	223.36	74.76	1,470
Warren	53-5F2	13	2,738	293,052	2,530	1.08	115.83	107.05	746
Chase Hill	56-155F4	10	4,271	196,734	1,485	2.88	132.48	46.06	660
Chopmist	53-34F3	30	2,663	292,444	852	3.13	343.24	109.82	1,832
Barrington	53-4F1	16	3,239	232,741	2,249	1.44	103.49	71.85	1,313
Chase Hill	56-155F6	24	2,526	257,992	1,573	1.61	164.01	102.13	624
Tioque	56-100F1	21	2,456	266,266	2,334	1.05	114.08	108.42	1,533
Centerdale	53-50F2	8	2,851	197,453	2,081	1.37	94.88	69.27	1,141
Dunnell Park	53-1201W4	8	2,819	185,097	850	3.32	217.76	65.67	178
Old Baptist	56-46F1	19	2,317	197,534	1,463	1.58	135.02	85.25	988
Jepson	56-37W5	22	2,233	192,263	1,308	1.71	146.99	86.10	517
Jepson	56-37W3	25	2,127	211,622	1,852	1.15	114.27	99.49	521
Woonsocket	53-26W1	26	2,255	179,889	1,528	1.48	117.73	79.76	750
Kenyon	56-68F2	36	2,548	274,652	4,296	0.59	63.93	107.81	1,153

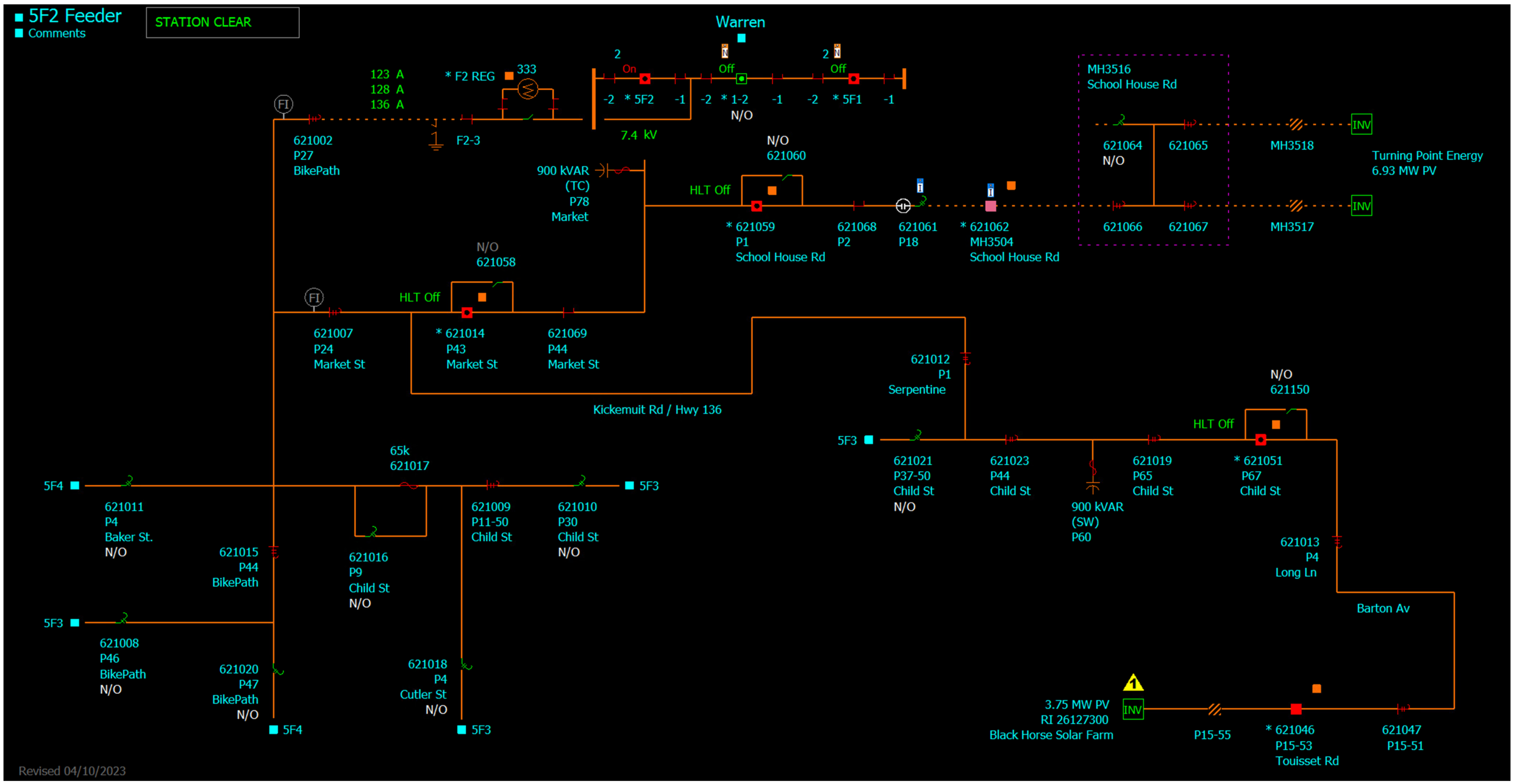
DIV 4-14-2

4F1 Circuit



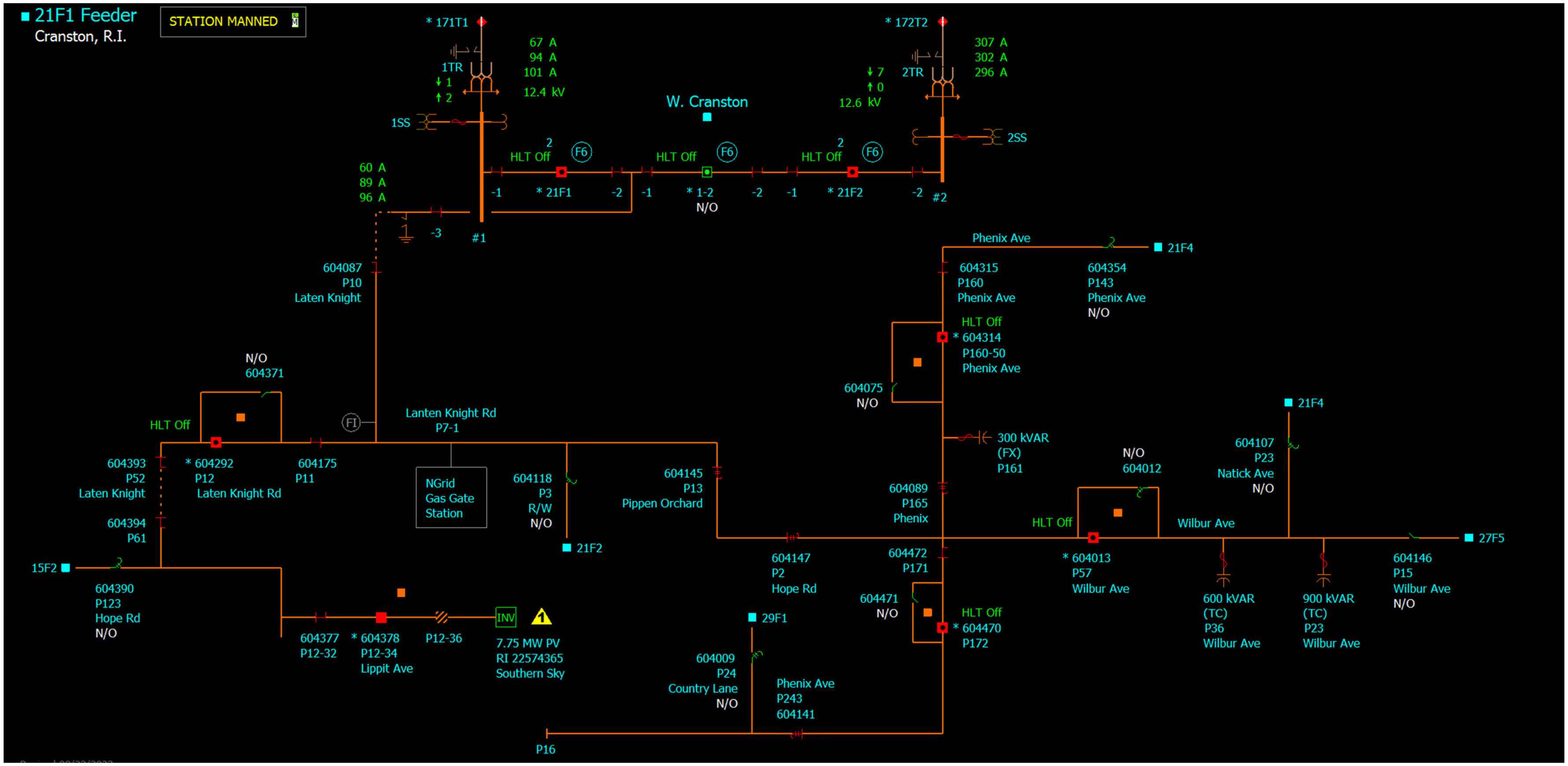
DIV 4-14-2

5F2 Circuit



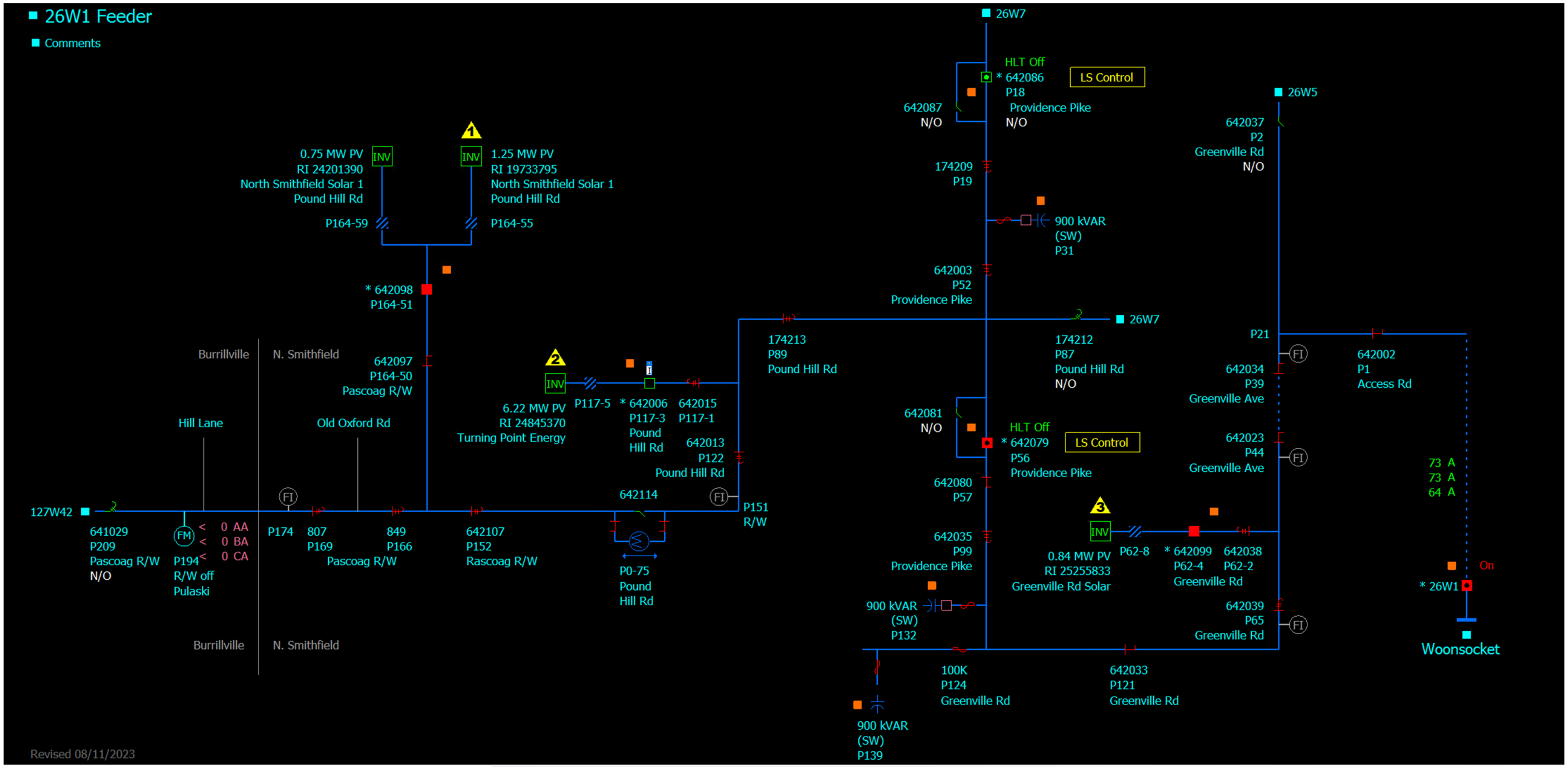
DIV 4-14-2

21F1 Circuit



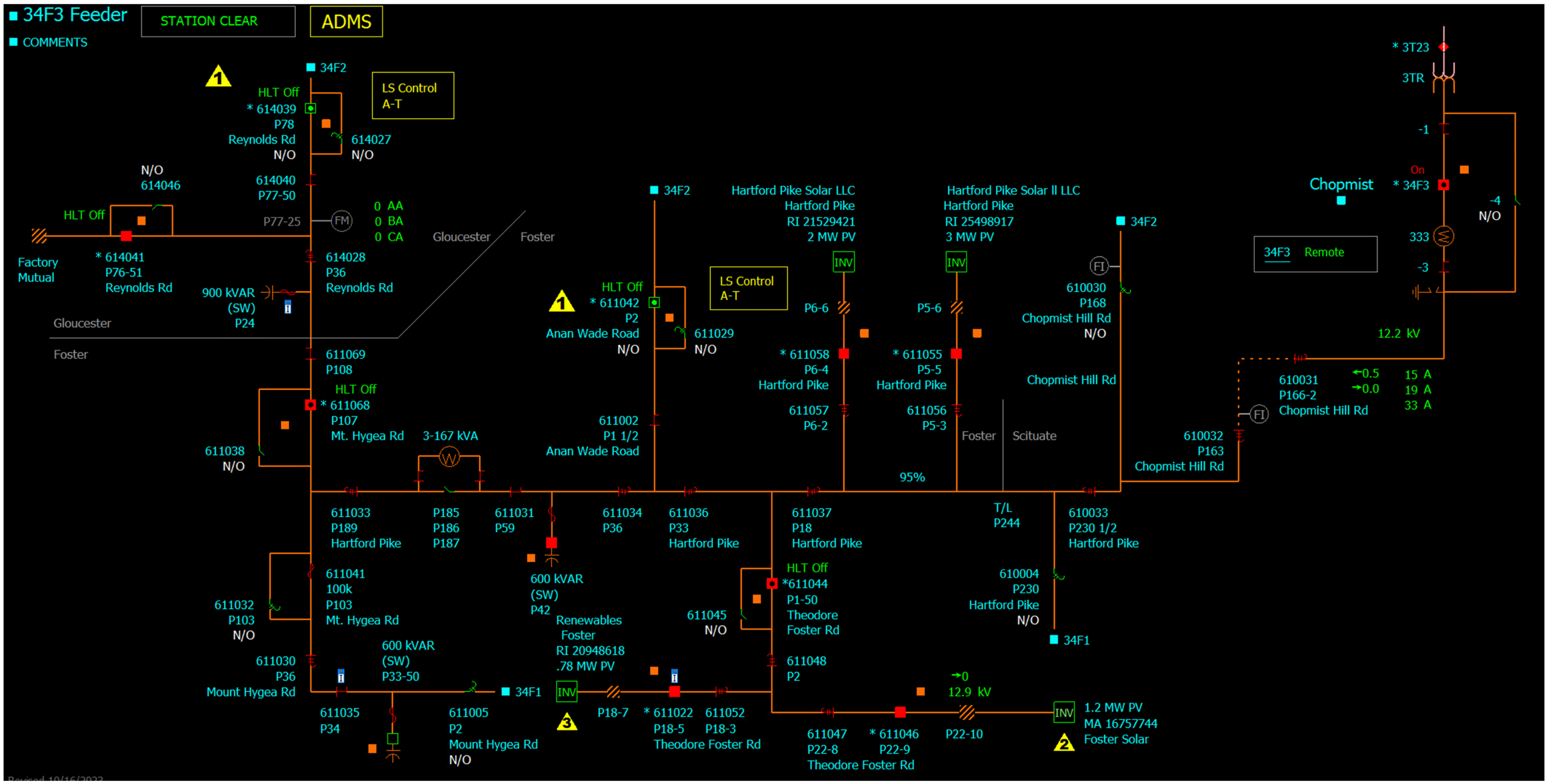
DIV 4-14-2

26W1 Circuit



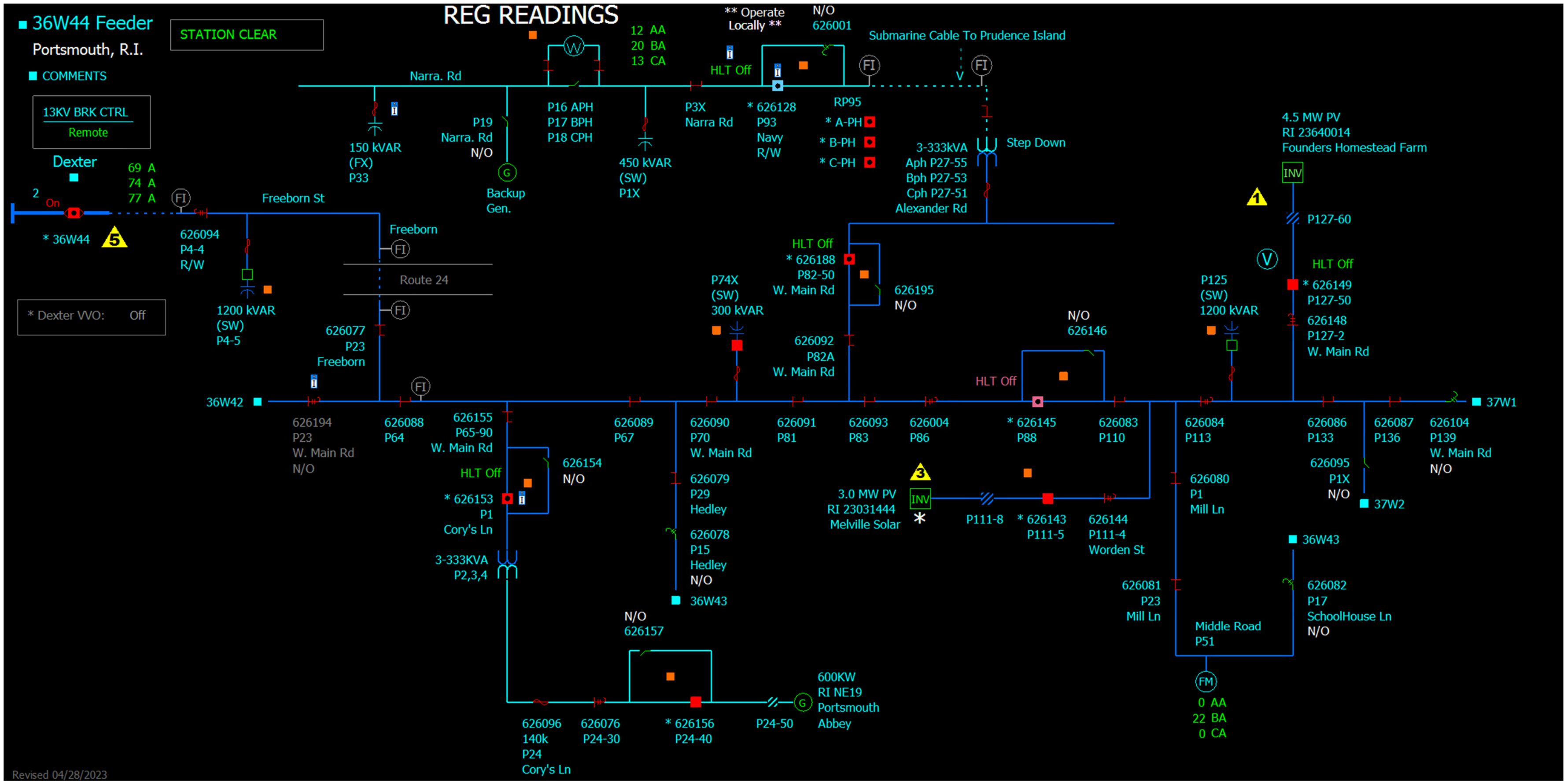
DIV 4-14-2

34F3 Circuit



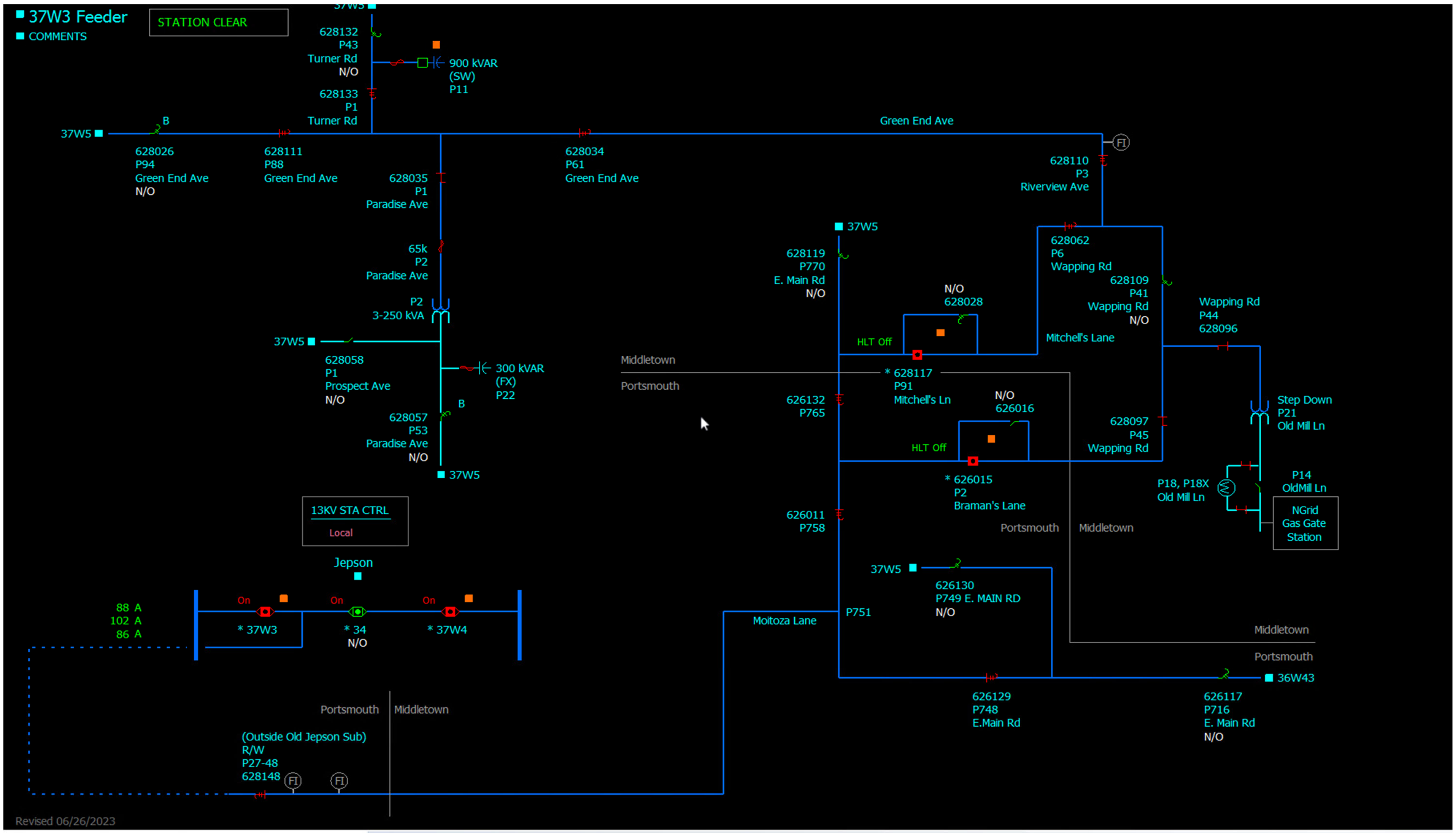
DIV 4-14-2

36W44 Circuit



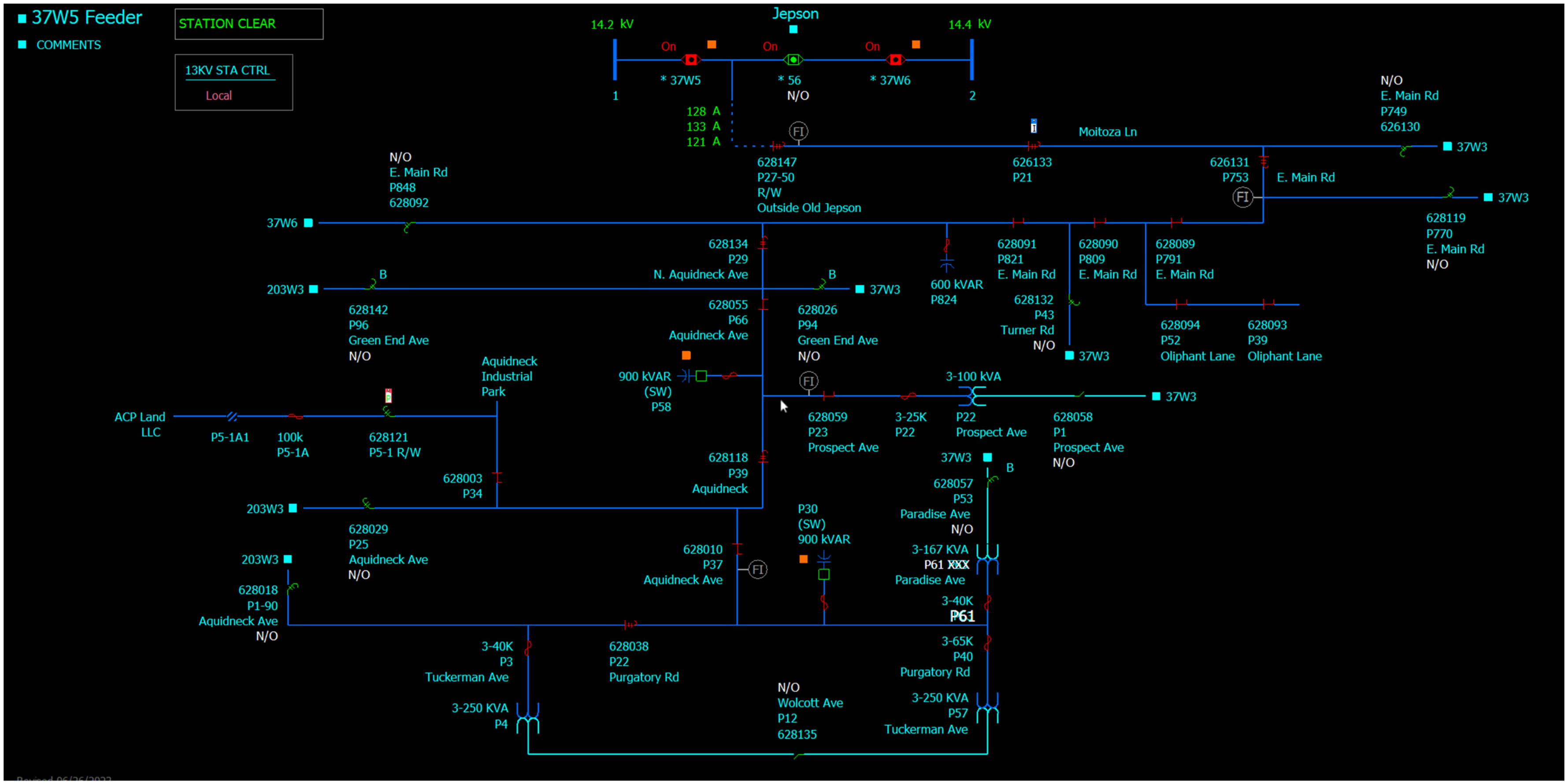
DIV 4-14-2

37W3 Circuit



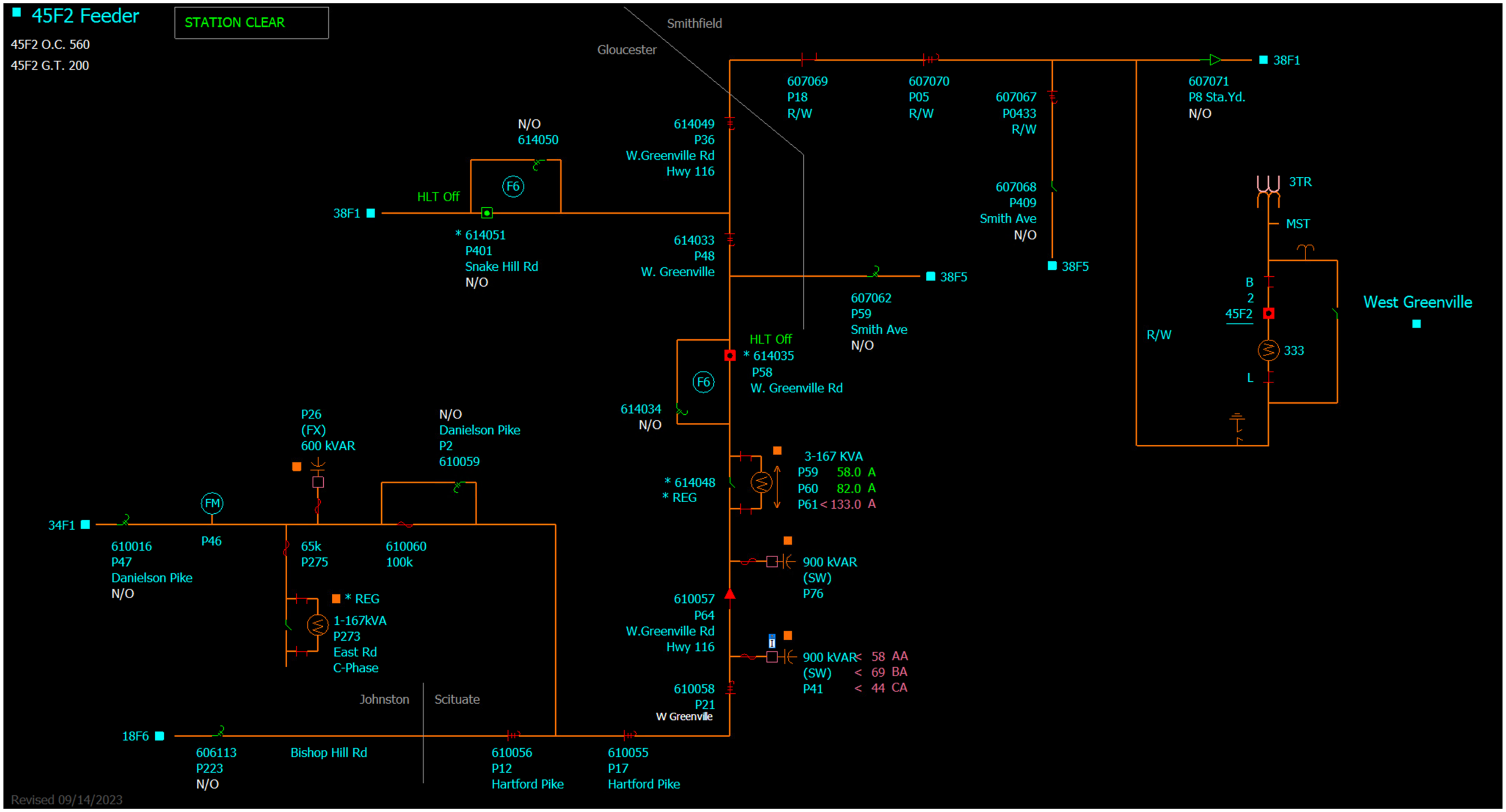
DIV 4-14-2

37W5 Circuit



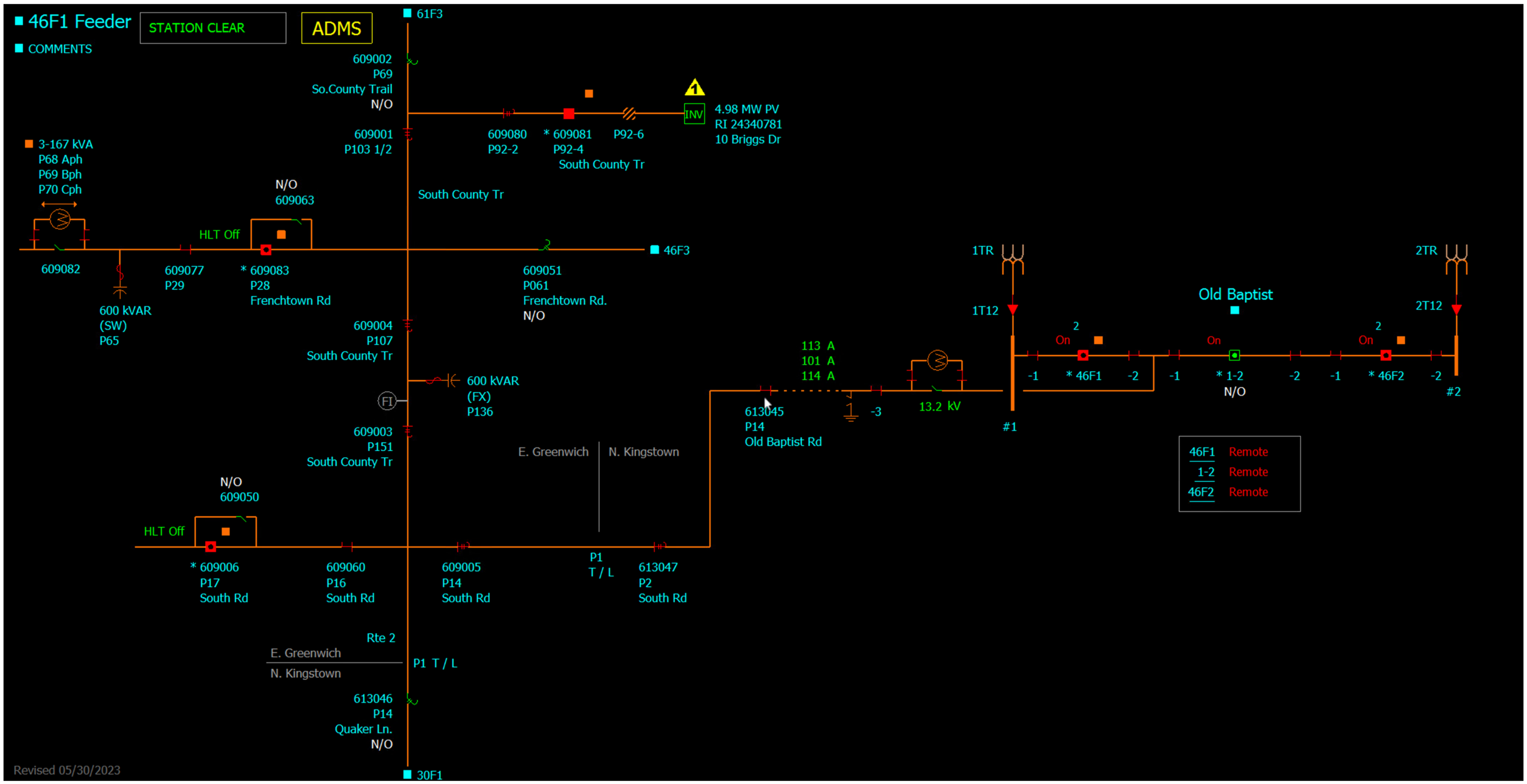
DIV 4-14-2

45F2 Circuit



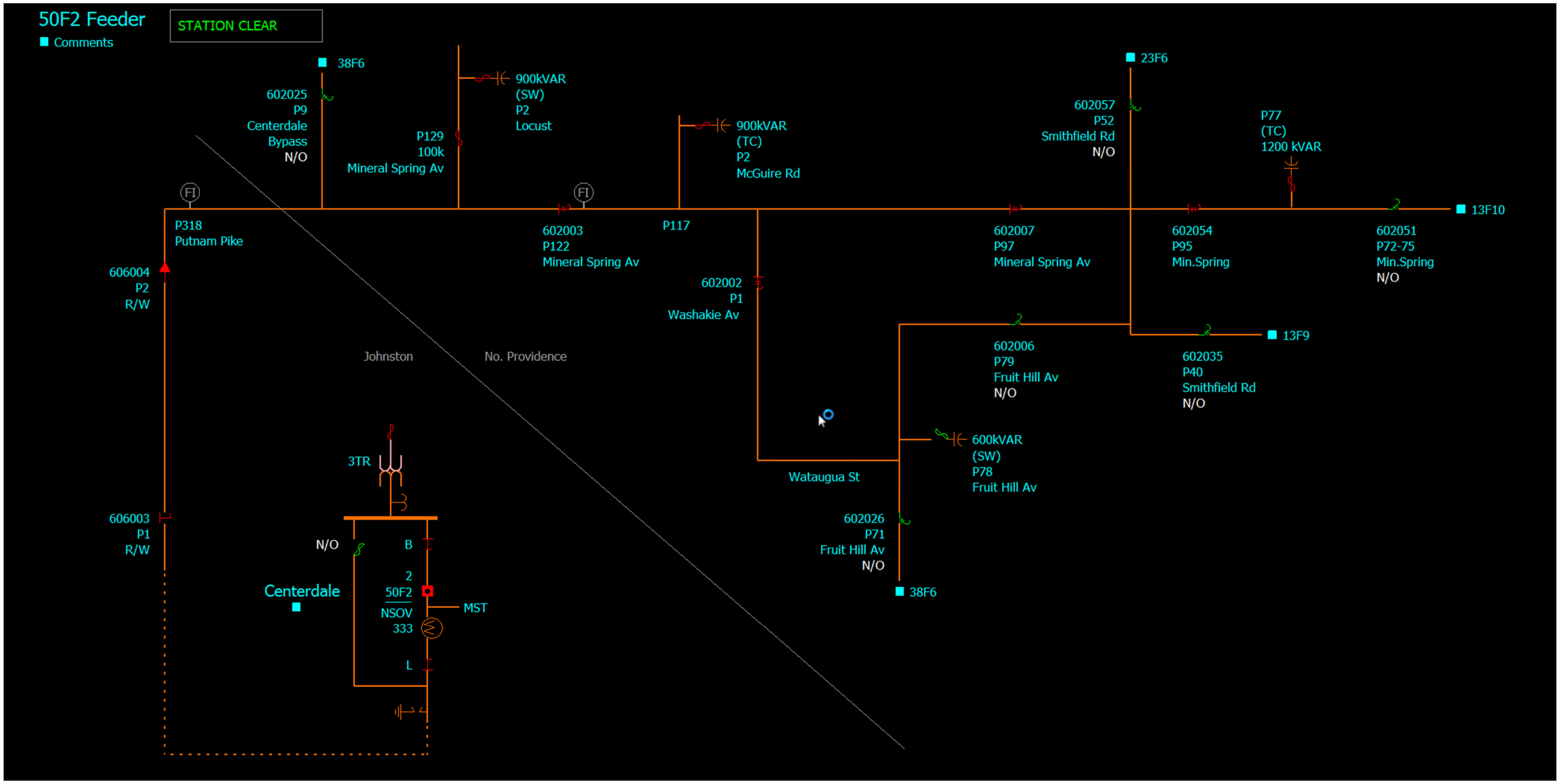
DIV 4-14-2

46F1 Circuit



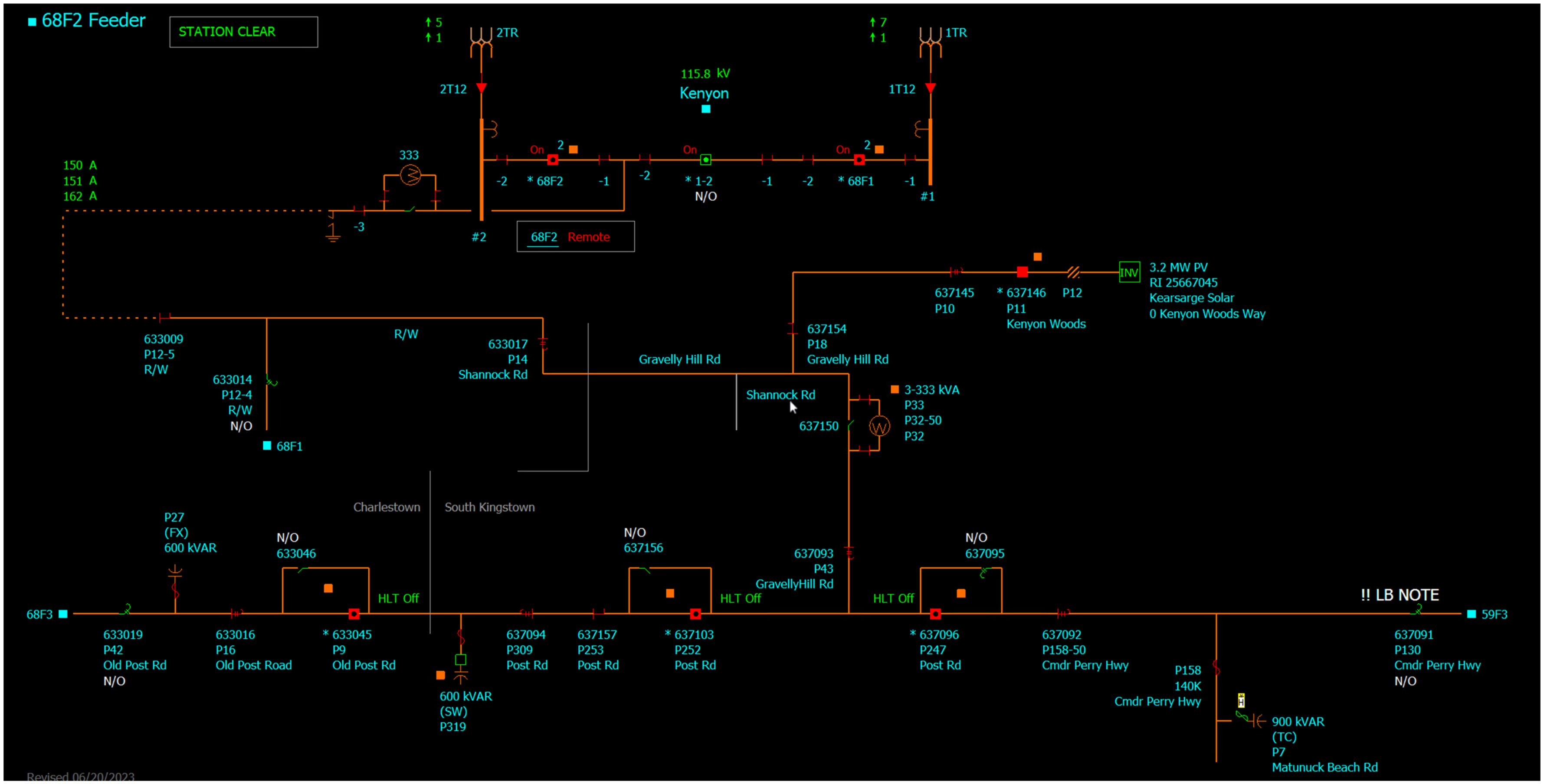
DIV 4-14-2

50F2 Circuit



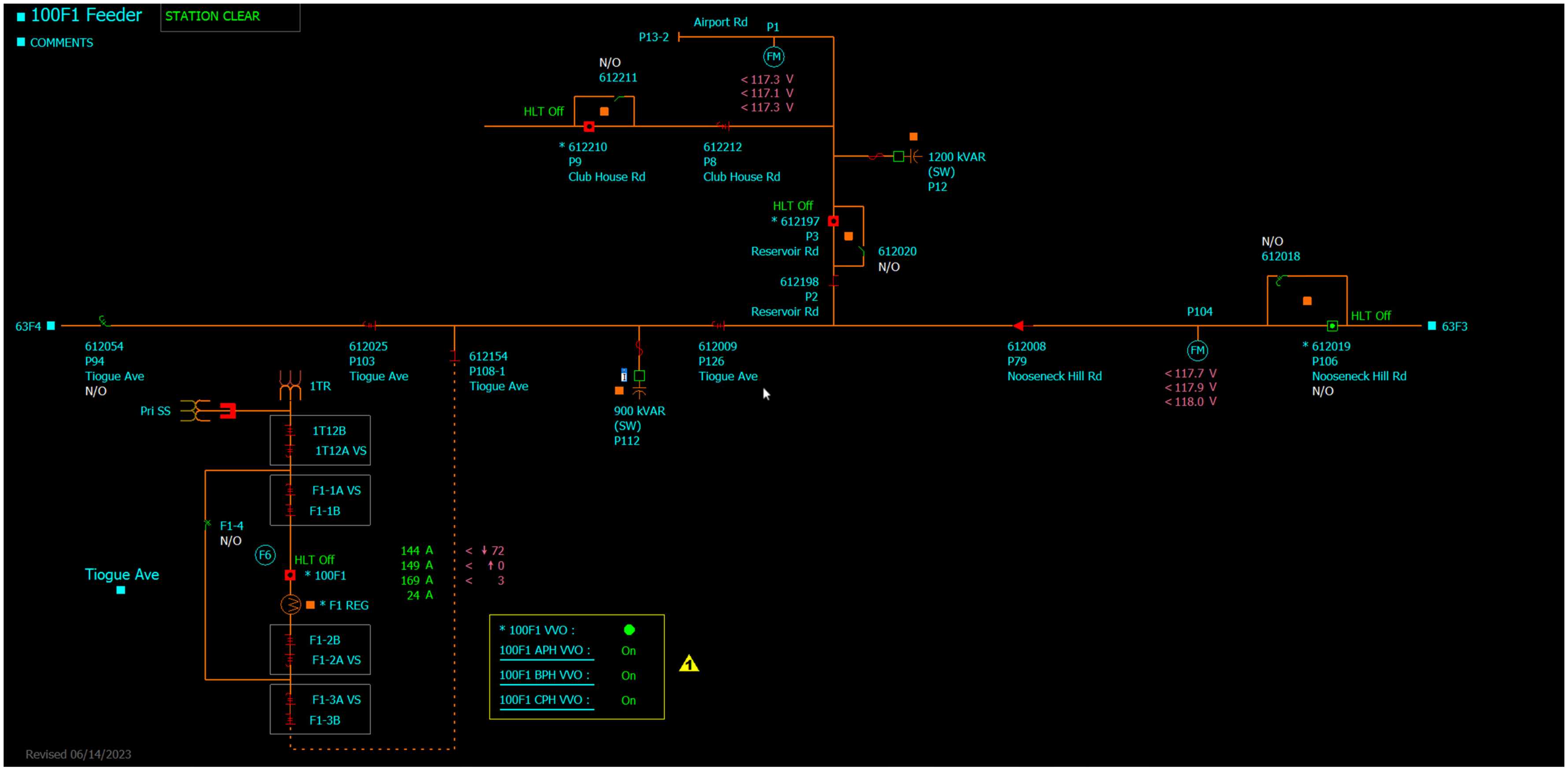
DIV 4-14-2

68F2 Circuit



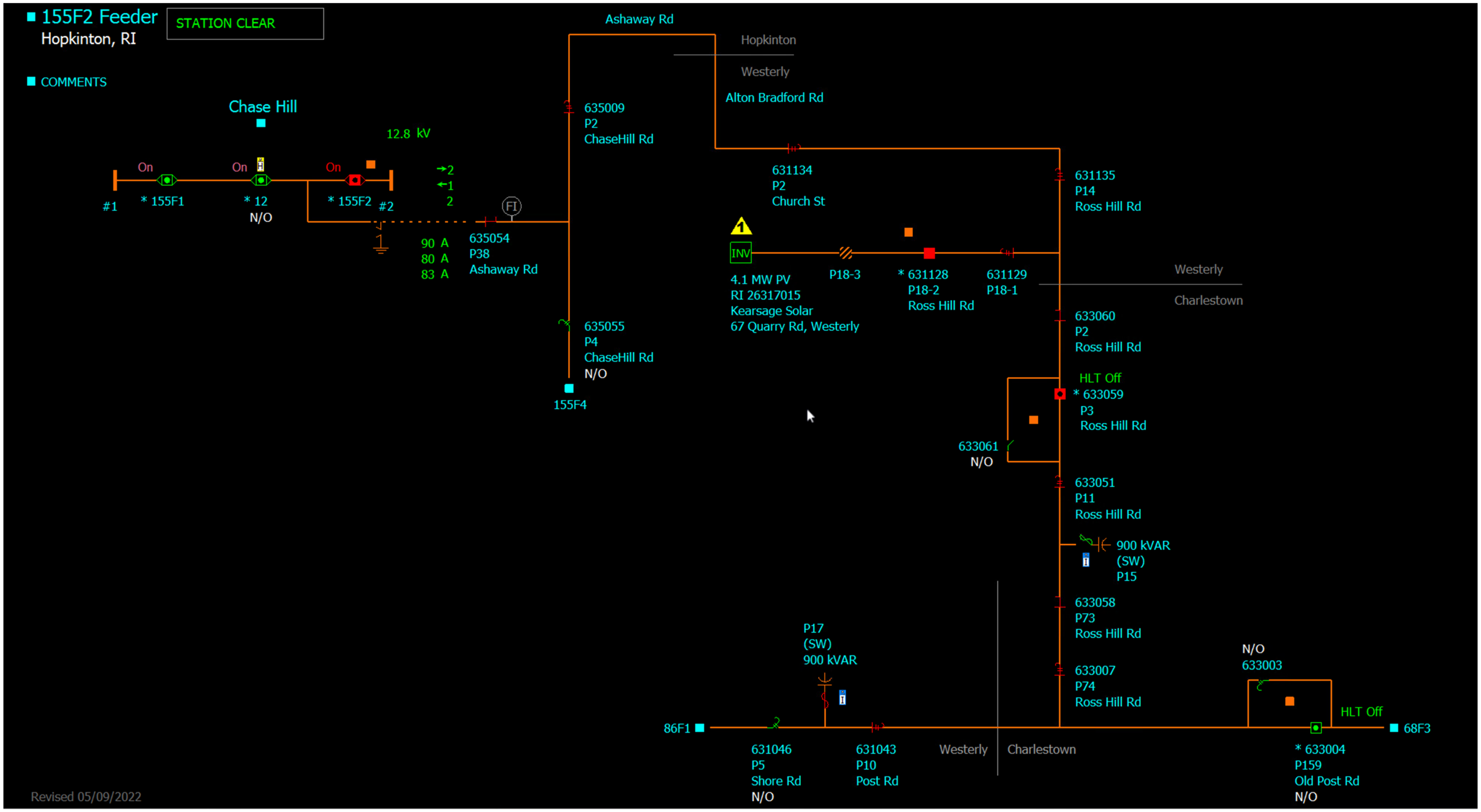
DIV 4-14-2

100F1 Circuit



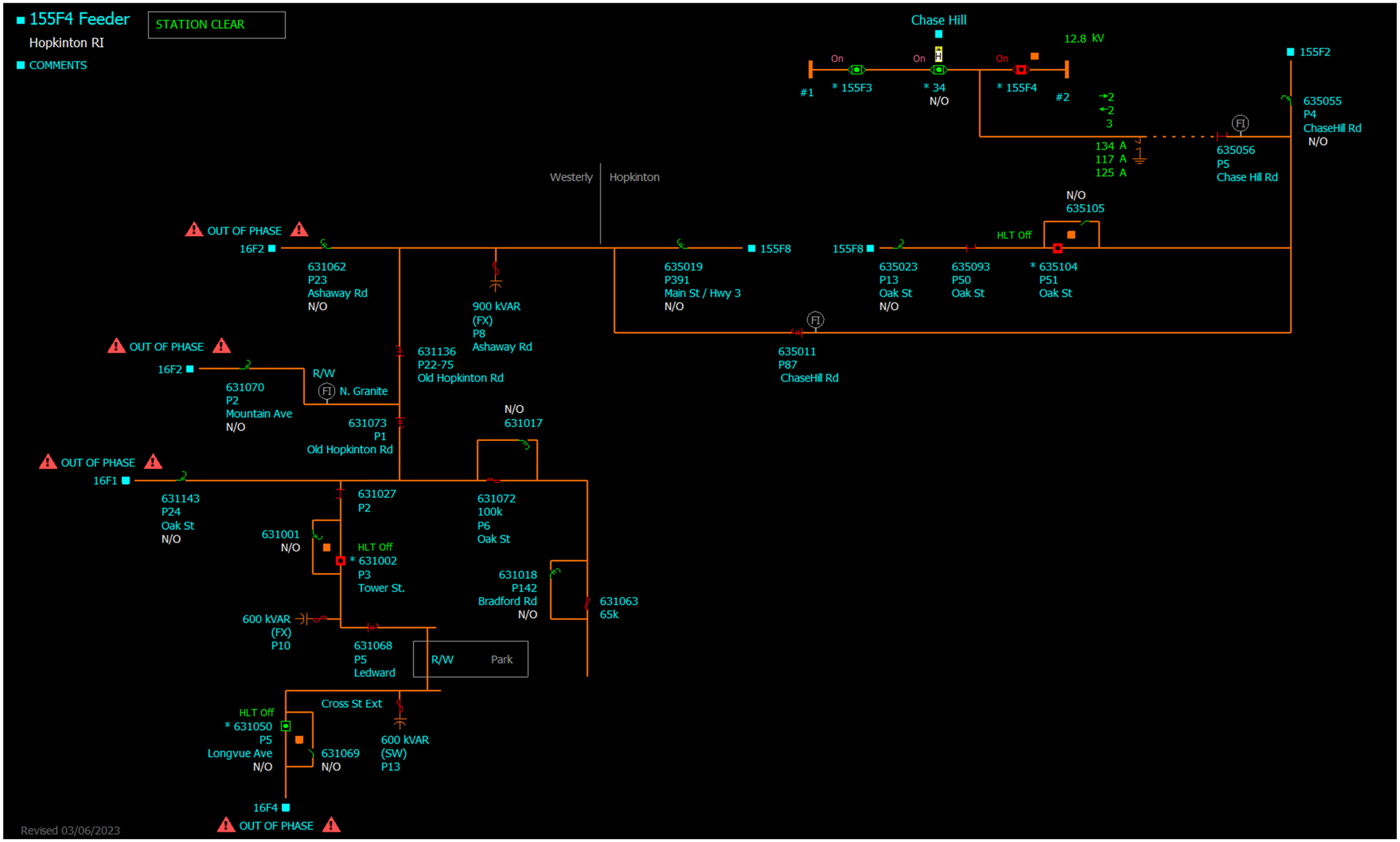
DIV 4-14-2

155F2 Circuit



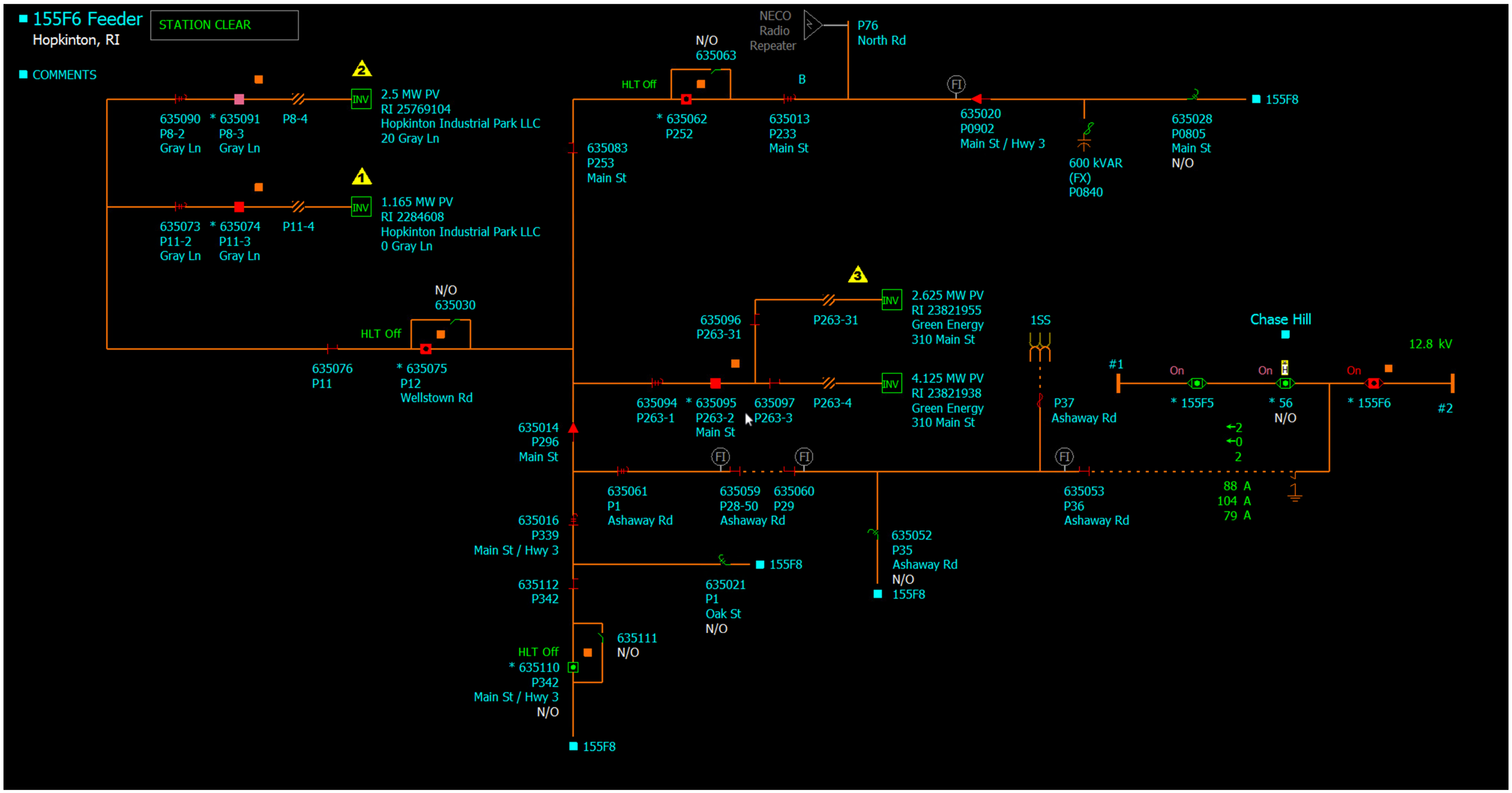
DIV 4-14-2

155F4 Circuit



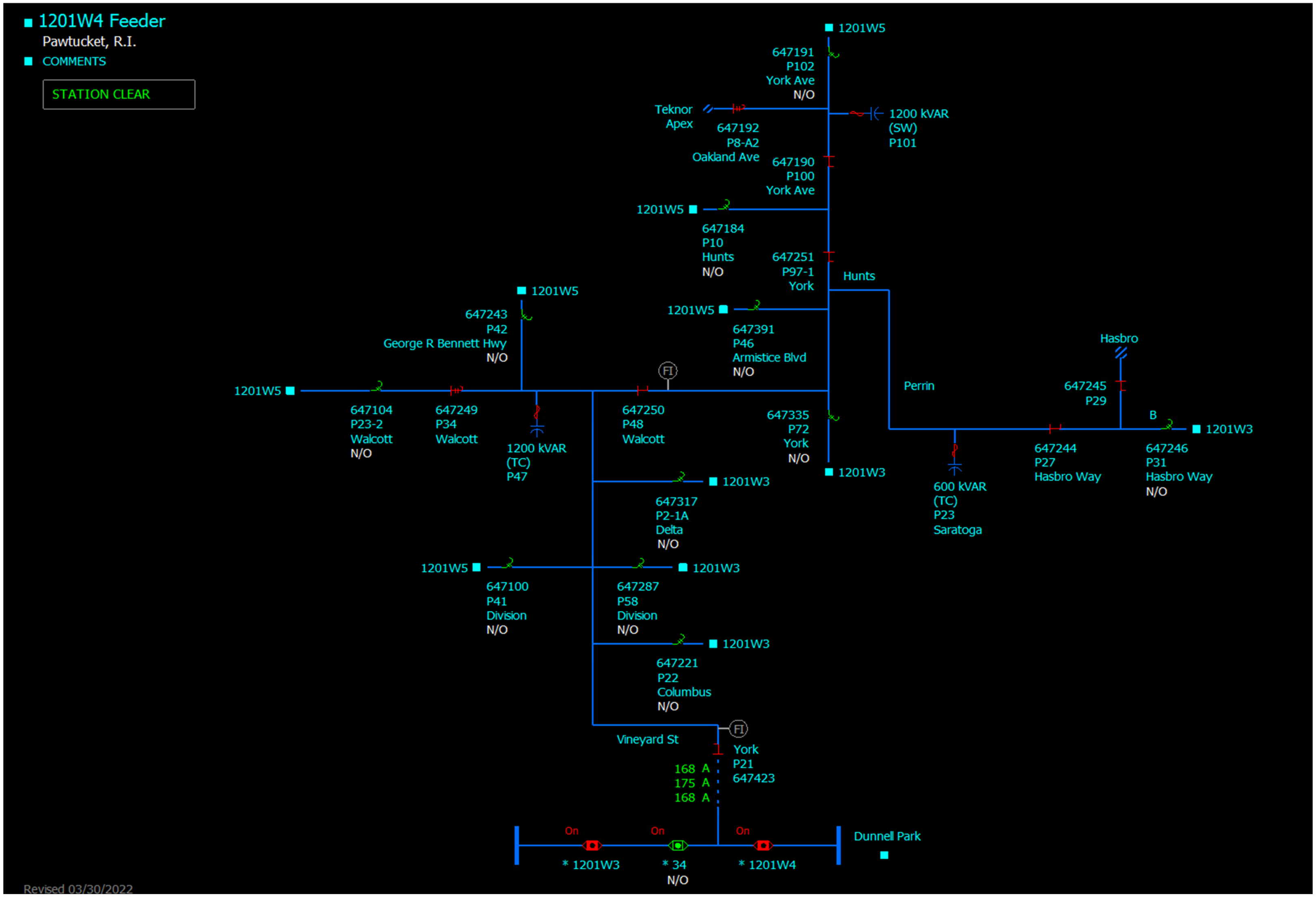
DIV 4-14-2

155F6 Circuit



DIV 4-14-2

1201W4



Attachment DIV 4-14-3

The Company provided the Excel file of Attachment DIV 4-14-3.

Division 4-15
CEMI-4, ERR and Distribution Automation – Various

Request:

How did RIE derive the FY 2025 budget of $4.5 million for the ERR program?

Response:

The FY 2025 budget figure of $4.5 million is based on approximately $2.0 million in traditional reliability improvements and approximately $2.5 million in distributed automation solutions.

With $2.0 million for reliability improvements to spread around 17 circuits, the Company can do many traditional, low-cost improvements and a few modest sized projects. Low-cost reliability projects include additional fusing to improve coordination and limit exposure, cutout mounted recloser installations to reduce temporary faults from causing permanent outages, spot trimming locations with recurring tree outages, adding animal protection in troublesome locations, and load balancing to even out customer counts and reduce neutral current. Other traditional reliability upgrades include line upgrades to covered wire, installing additional phases, closing-in gaps to create circuit loops, removal of distribution lines from off-road locations, adding in additional three-phase sectionalizing devices including reclosers, and more extensive trimming. The ERR program is built to handle modest improvements with significant reliability benefits. Large scale system upgrades uncovered through the circuit reviews will be handled through the standard capital project process outside of the ERR program.

The distributed automation solution aims to install 30 reclosers with communication capability, in addition to the reclosers that are identified to target specific poor reliability areas. These devices will be installed with microprocessor relays and high accuracy voltage/current sensing equipment to provide line protection, fault sensing, system monitoring and remote operation capabilities.

Prepared by or under the supervision of: Ryan Constable and Eric Wiesner

Division 4-16
CEMI-4, ERR and Distribution Automation – Various

Request:

In executable format, provide a BCA for the FY 2024 and FY 2025 ERR programs. Include all inputs and assumptions.

Response:

The Company provides Docket 4600 BCAs for new major projects and programs when submitting its December ISR Plan proposal filing. An ERR BCA will be included in the December filing. Also see the response to Division 1-16.

Division 4-17

CEMI-4, ERR and Distribution Automation – Various

Request:

Identify the number and cost of recloser installations expected annually for FY 2024 – FY 2029 under each program below. Separately identify mainline reclosers and reclosers with FLISR scheme.

CEMI-4

ERR

Distribution Automation

Other program (explain)

Response:

The following table shows the number and estimated cost of the recloser installation for FY 2024 – FY 2029 under each of the reliability programs. All reclosers will be mainline reclosers ultimately incorporated into a FLISR scheme. While the Company may have other projects that involve recloser installations, there are no other programs that will install reclosers.

		FY24	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**Total**
ERR	Count	0	30	30	30	30		120
	Cost	$0	$2,448,000	$2,521,440	$2,597,083	$2,674,996	$0	$10,241,519
CEMI	Count	4	45	34	34	34		147
	Cost	$320,000	$3,672,000	$2,857,632	$2,943,361	$3,031,662	$0	$12,824,655
DARP	Count	0	91	106	155	164	200	716
	Cost	$0	$7,425,600	$8,909,088	$13,418,263	$14,623,310	$18,368,304	$62,744,565
Total	Count	0	166	170	219	228	200	983
	Cost	$320,000	$13,545,600	$14,288,160	$18,958,707	$20,329,967	$18,368,304	$85,810,738

Prepared by or under the supervision of: Ryan Constable

Division 4-18
CEMI-4, ERR and Distribution Automation – Various

Request:

To the extent reclosers with a FLISR scheme are selected for each CEMI-4 and ERR reliability solution, explain in detail if that selection is in addition to remedying the root cause (such as animal guards, or vegetation management) and why it is required in addition to remedying the root cause of the outages.

Response:

All reclosers installed as CEMI-4 and ERR reliability solutions will be mainline reclosers incorporated into a FLISR scheme. Attachment DIV 3-21-2 provides details that can be used to understand how comprehensive solutions are developed in a cost-effective manner balancing outage mitigation measures with outage cause reduction measures. Outage cause reduction measures can sometimes be costly as compared to outage mitigations measures such as reclosers requiring a balanced approach.

Division 4-19

CEMI-4, ERR and Distribution Automation – Various

Request:

If added sectionalizing such as a recloser is a solution for an ERR or CEMI-4 project, explain in detail why it is necessary to have complete automation and communication package installed on the recloser as opposed to a less expensive sectionalizing device installation.

Response:

Because sectionalizers can and often include communication packages to be incorporated into FLISR schemes, it is unclear from the request whether the question is about the use of reclosers versus sectionlizers or whether communication packages are necessary. The Company will address each question separately.

Sectionalizers are used in combination with upstream reclosers or breakers to isolate a faulted section as the upstream fault current protective device proceeds through its reclosing steps. They were historically used in locations where coordination was challenging as they were marginally less expensive than a recloser with substantially less functionality (no fault interrupting capability). The reclosers installed under the ERR and CEMI-4 programs will ultimately be incorporated into FLISR schemes and do not have coordination challenges. Using sectionalizers with no communication packages instead of reclosers will undermine a substantial portion of the expected reliability benefits as a result of FLISR and create early obsolescence.

Regarding communication packages, the communication package has been a part of the standard recloser for approximately 5 years. It is necessary for system visibility and control, to create operational efficiencies, obtain the reliability benefits associated with FLISR, and to avoid early obsolescence.

Division 4-20

CEMI-4, ERR and Distribution Automation – Various

Request:

Provide a cost and benefit analysis between installing a sectionalizing device (recloser, fault saver or sectionalizer) without a full communication package and installing a recloser with a full communication package. Include all communication system costs. Explain in detail all the reliability benefits which the customer will actually experience under either scenario. Additionally, explain the incremental benefits which may occur if there is an outage which a FLISR scheme would actually function to reduce outage time.

Response:

The Company cannot provide a cost-benefit analysis between installing a sectionalizing device (recloser, fault saver or sectionalizer) without a full communication package and installing a recloser with a full communication package. For approximately the past 5 years, the Company's standard mainline recloser included remote operation capability. The Company does not have a mainline recloser type without the communication package to present a difference in cost. Also see the response to Division 3-23.

The reliability benefits are described in detail in the Distribution Automation Recloser Program document (pages 120-135). Also see the response to FY 2024 Division 3-15.

Division 4-21

CEMI-4, ERR and Distribution Automation – Various

Request:

What are RIE's expected system SAIFI and SAIDI improvements attributable to each of the following programs if implemented as proposed in the FY 2025 ISR Plan: CEMI-4, ERR and Distribution Automation. Provide separately for each program and for each year from FY 2025 to FY 2029. Include supporting calculations.

Response:

The SAIFI improvement for the Distribution Automation Recloser Program is stated in Section 4.6 of the program documentation (page 129). It is a 25% reduction in main line SAIFI or a 0.17 reduction in system SAIFI. SAIDI is also expected to decrease by approximately 25%.

With respect to the CEMI-4 program, please see the Company's responses to FY 2024 ISR Plan Data Request Division 2-2 and FY 2025 ISR Plan Data Request Division 3-12, part c.

The SAIFI and SAIDI improvements associated with the ERR program have not been calculated.

Division 4-22

CEMI-4, ERR and Distribution Automation – Various

Request:

What are RIE's expected system SAIFI and SAIDI improvements attributable to each of the following programs if implemented without any FLISR Recloser schemes: CEMI-4, ERR, and Distribution Automation? Provide separately for each program and for each year from FY 2025 to FY 2029. Include supporting calculations.

Response:

The SAIFI improvement for the Distribution Automation Recloser Program if no distribution automation is implemented could be approximated to be half of the 25% reduction in main line SAIFI, or 0.085 reduction in system SAIFI. Also see the response to Division 4-37.

It was explained that the SAIFI and SAIDI impacts of the CEMI-4 program were small and theoretically calculated to 0.008 in the response to FY 2024 ISR Plan Data Request Division 2-2 and notes as trivial in FY 2025 ISR Plan Data Request Division 3-12, part c. This is true with or without distribution automation.

The SAIFI and SAIDI improvements associated with the ERR program have not been calculated with or without distributed automation.

Division 4-23
CEMI-4, ERR and Distribution Automation – Various

Request:

Is RIE assuming that the recommended solution set for targeted circuits in the CEMI-4 and ERR programs will always include recloser installations? If so, please explain how a solution can be derived before knowing the problem or need?

Response:

RIE includes an amount in the CEMI-4 and ERR cash flows for reclosers for purposes of program development. This is based on a test set of circuits for the CEMI-4 program and past experience for the ERR program. In this manner, the Company appropriately sized the program. Assumptions such as these using best available information to setup programs are not new and are common. Actual solution development does not assume reclosers will always be included.

Prepared by or under the supervision of: Ryan Constable

Division 4-24

CEMI-4, ERR and Distribution Automation – Various

Request:

Why are reclosers the only solution considered for circuit reliability improvement under the distribution automation program? Why are lower cost alternatives not evaluated in the program documentation? How can RIE derive a solution before knowing the problem or need?

Response:

The Distribution Automation Recloser Program explains that mainline outages make up approximately 80% of the frequency metric (pages 128 to 129). Installing reclosers to better sectionalize the feeder and installing open point reclosers provides substantial benefits as described in the program documentation and the response to FY 2024 Division 3-15.

Decisions will be made during engineering of each feeder within the program to best place the reclosers and select the open points which provide the best benefits. In this manner, the most cost effective solution to address the mainline reliability issue is derived.

RIE cautions the belief that lower cost alternatives exist that can provide the reliability benefits contemplated by reclosers. Simple reconfiguration for system optimization is performed as necessary for a variety of system issues outside of any program. Alternatives such as line redesign to avoid trees or vehicles, undergrounding, or energy storage are substantially higher in cost than reclosers.

Division 4-25

CEMI-4, ERR and Distribution Automation – Various

Request:

Provide an update on the Company's Infrastructure Investment and Jobs Act (IIJA) funding proposals. Explain in detail how a potential grant award will impact the 5-year ISR Plan and/or Long Range Plan. Include the types of investments RIE may implement, overlap with current proposed investments, RIE's matching cost responsibilities, how and when the grant award will reduce ISR Plan spend, etc.

Response:

Rhode Island Energy has submitted two proposals for IIJA Funding. The application for Grid Resilience was not selected. The application for Smart Grid was selected to advance to award negotiations. Contingent on successful award negotiations, Rhode Island Energy will apply the federal funding to investments proposed within the annual ISR, which could include, advanced reclosers, smart capacitors, regulators, and electromechanical relays, in accordance with the award agreement and subject to annual regulatory review and approval, as appropriate.

Rhode Island Energy will update the 5-year ISR and LRP accordingly following the award negotiation process. This federal funding award requires the selected applicant to provide supplemental non-federal funding equivalent to at least 100% of federal funding; however, the exact details of the cost match for Rhode Island Energy's funding proposal have yet to be finalized within the award negotiation process. The award negotiation process is expected to go through the first quarter of 2024, and the Company will provide an update when this is complete.

Division 4-26
Distribution Automation

Request:

For Distribution Automation, is the Company using outage data based on the Rhode Island PUC definition of sustained interruption (loss of electric power lasting equal to or more than one minute) or the IEEE definition (loss of electric power lasting five or more minutes) to select circuits? Will the Company measure and report results using the same methodology? If not the same, why?

Response:

The Company used outage data based on the Rhode Island PUC definition of sustained interruption to select the Distribution Automation circuits for the program's first year because it matched the Company's legacy software. When initially reporting program results, both methods will be used.

The Company does intend to transition the Distribution Automation program to an IEEE definition with a loss of power lasting five or more minutes. This transition is important and necessary for the Distribution Automation program as the FLISR schemes typically trigger in less than 2 minutes, but more than 1 minute.

Division 4-27
Distribution Automation

Request:

Is the Company using reliability data with or without storms to rank circuits in the Distribution Automation Program (page 127)?

Response:

The Company uses reliability data without storms to rank circuits in the Distribution Automation Program (page 127).

Prepared by or under the supervision of: Ryan Constable

Division 4-28
Distribution Automation

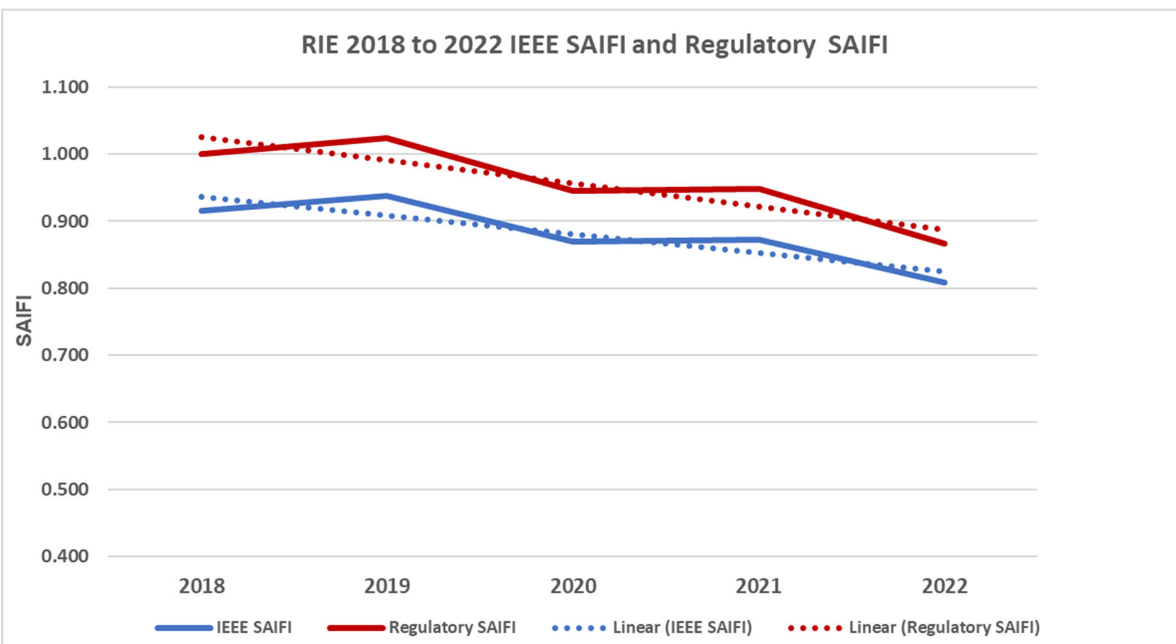
Request:

Provide the RIE historic SAIFI and SAIDI performance with trend lines (Figures 1 and 2, pp 124) for the past five years. Is RIE's system performance declining, steady, or improving over that time?

Response:

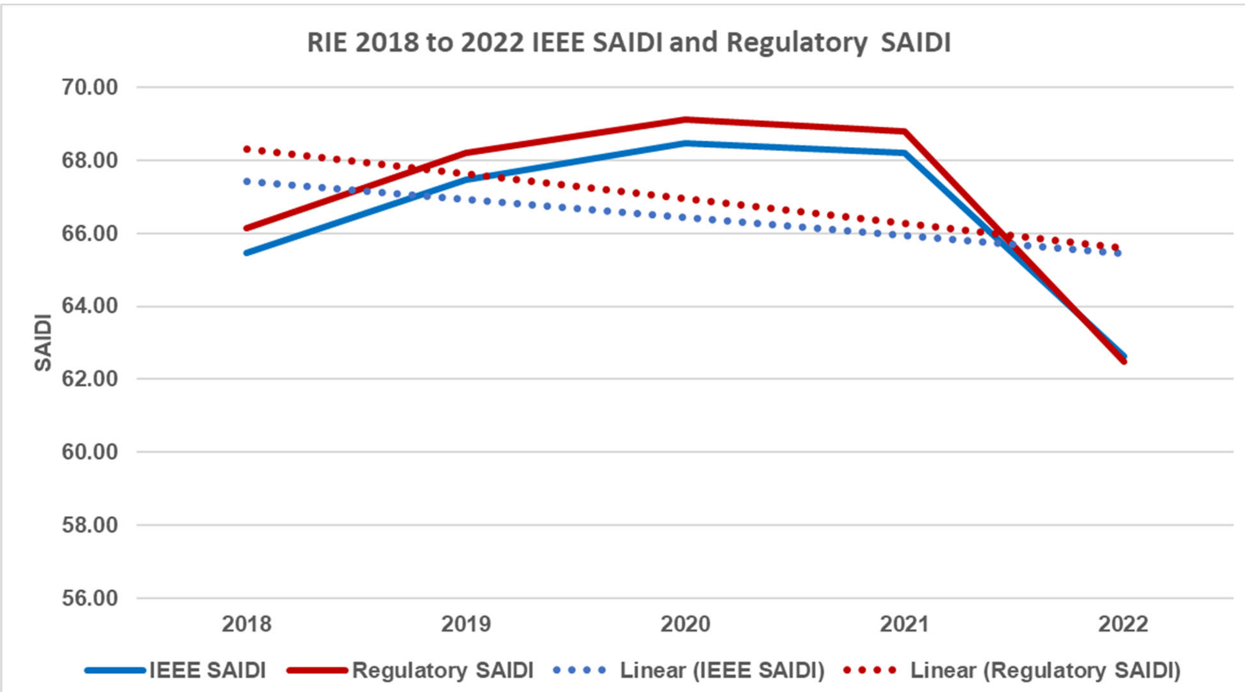
Figure 1 and Figure 2 are RIE historic SAIFI and SAIDI performance in the past five years. Both SAIFI and SAIDI are showing improvement over this period.

Figure 1. RIE historic SAIFI performance



Division 4-28, page 2
Distribution Automation

Figure 2. RIE historic SAIDI performance



Division 4-29
Distribution Automation

Request:

Regarding page 132, the Distribution Automation program cash flows and equipment counts indicate 1,000 reclosers planned through 2031 at a cost of $90 million.
How did RIE determine the targeted number of recloser installations for the entire system (1,267)?

a. How many of the 336 circuits to be reviewed for eligibility will ultimately receive distribution automation investments?

b. Will all reclosers have the FLISR scheme installed under the Distribution Automation program?

c. The cost of a recloser is estimated at $80,000. Does this include FLISR?

d. Provide all analysis demonstrating the need for reclosers on each proposed circuit.

e. How does RIE know how many reclosers will be transferred to the CEMI and ERR programs if the targeted circuits have not been identified, outage causes have not been analyzed, and solutions development has not occurred which may, or may not, include a recloser?

f. Provide descriptions with cost and implementation timeline for all other systems/communication required for the Distribution Automation program. Where are those investments included in the ISR Plan?

g. Is basic ADMS a prerequisite? Will RIE incur any costs to either implement or support basic ADMS on an annual basis? If so, where are investments included in the ISR Plan?

h. Provide cost estimates with an explanation.

i. Will Distribution Automation require advanced ADMS?

j. How did RIE develop the budget? In executable format, provide a detailed breakdown of the proposed budget, by year. Include annual O&M as a separate line item.

k. Will the program end after five years?

Division 4-29, page 2
Distribution Automation

Response:

RIE determine the targeted number of recloser installations for the entire system (1,267) by taking the total customer count 497,500 divided by 500 customers per recloser, which results in an approximate mainline recloser count of 995 reclosers. Then subtracting the 400 existing and adding 2 open point reclosers per feeder for the feeders under consideration (336) equals 1267.

a. RIE set up the program to consider distribution automation on all 336 circuits or for system-wide deployment.

b. Yes, all reclosers will be incorporated into a FLISR scheme.

c. Yes, the cost of a recloser, estimated at $80,000, includes FLISR.

d. The analysis necessary to demonstrate the need on each circuit is shown in the Distribution Automation Recloser Program document (pages 120-135). The Company expects continued discussions with the Division and the requirement to demonstrate actual performance, in order to agree upon execution of future program years.

e. RIE shifted an allocation of reclosers to the CEMI-4 and ERR programs based on preliminary program analysis to setup the programs. This ensures the programs are not under estimated. The Company will provide the Division with circuit-specific analyses at the appropriate design stage.

   Like other advanced devices with full communication packages there will be annual run the business communication costs. The recovery of these costs are not currently being proposed through the ISR.

f. Basic ADMS will be implemented during calendar year 2024 as part of the transition from National Grid USA ownership to PPL Corporation ownership and will come with FLISR functionality. Also see the response to Division 3-31. ADMS should not be considered a prerequisite such that no recloser investments should occur until the ADMS system is online. The Company has been installing advanced reclosers for approximately five years. RIE will incur annual costs for continuous improvement continuous development (CICD) as well as a maintenance and support costs which is paid for upfront for a 5 year period for ADMS, however, these costs will not be recovered in the ISR.

Division 4-29, page 3
Distribution Automation

g. See the response to Division 3-31. ADMS will be implemented as part of the transition.

h. Distribution Automation does not require advanced ADMS.

i. The Distribution Automation budget was set up as described in the program document (pages 131 to 132). Attachment DIV 4-29 provides a detailed breakdown of the proposed budget, by year including annual O&M as a separate line item.

j. The Distribution Automation program is currently setup to end after 7 years.

Attachment DIV 4-29

The Company provided the Excel file of Attachment DIV 4-29.

Prepared by or under the supervision of: Ryan Constable

Division 4-30
Distribution Automation

Request:

The Company states that main line events, including major storms, interrupted an average of 1,285 customers in the previous 5 years (page 128). RIE estimates that approximately 50% of main line events can be addressed by sectionalizing (page 128).

a. How many customers would see improvement if 50% of events are addressed and explain exactly what is meant by the phrase "events are addressed"?

b. How is that number calculated? How does that number compare to the 498,827 customer count that RIE uses in the USDOE Ice Calculation on page 130?

c. Does RIE assume that all customers on the system benefit even if they are not served from circuits with distribution automation?

d. Do the benefits in Table 10 (page 130) assume that all 498,827 customers will experience reliability improvements starting with the first year? If so, how is that realistic given that improvements are implemented over five years and would not affect all customers? If RIE's inputs are not accurate, please revise the table to reflect the expected customer counts each year and explain the basis for the revisions.

Response:

a. All the customers in the existing protection zone would see an improvement. "Events are addressed" means the customers would no longer see the event. For example, if the protection zone is serving 1285 customers, was sectionalized in half, and assuming the events split evenly between the two new zones, all 1285 customer would see 50% less outages. This includes an open point recloser as included in the program.

b. The 1,285 number is calculated by taking the average customers impacted by main line events. The 50% factor is a reasonable factor assuming the protection zone is split in half. The numbers are used to derive the estimated frequency improvement that is then input into the USDOE ICE Calculator as described in the program documentation (page 129). The frequency improvement was then applied to the subset of customers included in the program. However, RIE incorrectly used the entire customer population of 498,827 customers as noted by the Division in recent discussions. The revised subset of customers is approximately 465,500, which excludes customers on underground circuits and other circuits which will not be considered within the program. Revised USDOE ICE Calculator details will be provided in the December filing.

Prepared by or under the supervision of: Ryan Constable

Division 4-30, page 2

Distribution Automation

c. No, see the response to part b.

d. The benefits in Table 10 (page 130) assume that all customers in the program will experience reliability improvements starting with the first year. This is a method to simplify the benefit cost analysis in a concise 20-year period. Please see the response to Division 3-25. Staggering the customer counts per year will also extend the evaluation period and have a marginal impact on the benefit-cost ratio.

Prepared by or under the supervision of: Ryan Constable

Division 4-31
Distribution Automation

Request:

What is the cost of system capacity upgrades necessary for each FLISR location and scheme area to be fully functional and capable of complete load transfer? Is this cost included in the $90 million proposed budget?

Response:

There are no capacity upgrades planned for each FLISR scheme. Therefore no costs are included. RIE does address small capacity conductors through its area study process and in consultation with the Control Center independent of any distribution automation program.

Prepared by or under the supervision of: Ryan Constable

Division 4-32
Distribution Automation

Request:

Provide all inputs and assumptions used in the USDOE ICE calculations (page 130). What inflation rate and discount rate did the Company assume in the calculator and why?

Response:

The Company used the default ICE calculator values of 2% for inflation rate and 6% for the discount rate. They were used as simple default values. Also see the response to Division 3-27.

Prepared by or under the supervision of: Ryan Constable

Division 4-33
Distribution Automation

Request:

Why does the Company only consider residential customers in its USDOE ICE calculations to support the need for the CEMI-4 program but considers all classes of customers in its USDOE ICE calculation for Distribution Automation? Are there other differences in BCA development between the programs, and if so, why?

Response:

The Company generally considers all classes of customers, however the CEMI-4 program focuses on customers in the more remote areas of the system. Therefore, the Company set the CEMI-4 customers to all residential to be intentionally conservative in its benefit-cost analysis. The BCA methods are described in the respective program documentation (pages 128 to 130 and 145 to 147). There are differences in assumptions as the programs are different.

Prepared by or under the supervision of: Ryan Constable

Division 4-34
Distribution Automation

Request:

In executable format, provide all underlying data and calculations relied upon to develop the BCA in Figure 10 (page 130). Include all assumptions and calculations to determine the expected reliability improvements each year as the program progresses, including customers impacted. Indicate revisions or refinements resulting from RIE's response to DIV-4-30.

Response:

Attachment DIV 4-34 includes the underlying data and calculations relied upon to develop the BCA in Figure 10 (page 130) including customers impacted. The assumptions and calculations to determine the expected reliability improvements are shown in the program document (pages 128 to 130). Two tables are presented; 1) with the simplified 20-year analysis with customers assumed at the beginning of the program, and 2) with staggered customers per Division 4-30. This response also contains revised total customer counts as described in the response to Division 4-30.

Attachment DIV 4-34

The Company provided the Excel file of Attachment DIV 4-34.

Prepared by or under the supervision of: Ryan Constable

Division 4-35
Distribution Automation

Request:

Provide the cost and benefit information in Figure 10 (page 130) assuming that all proposed reclosers are installed without an automated scheme. Provide all assumptions, inputs and underlying calculations in executable format.

Response:

Attachment DIV 4-35 shows the cost and benefit information assuming that all proposed reclosers are installed without an automated scheme.

Attachment DIV 4-35

The Company provided the Excel file of Attachment DIV 4-35.

Prepared by or under the supervision of: Ryan Constable

Division 4-36
Distribution Automation

Request:

For each FLISR scheme proposed to be installed in FY2025 ISR Plan, how many times over a 20 year period will the scheme operate to reduce outage minutes from maximum expected times to least expected number of operations? Describe in detail how RIE developed those estimates and provide supporting data.

Response:

The Distribution Automation Recloser Program is setup to achieve a 25% reduction in main line interruption frequency, from 0.68 to 0.51 resulting in a difference of 0.17.

0.17 * 465,500 customers in the program = 79,135 customers saved per year. With 1267 reclosers roughly grouped in schemes of 3 for purposes of this response results in 422 schemes. Each scheme would be capable of saving approximately 500 customers per operation.

79,135 / 500 customer per operation = 158 operations per year.

Each scheme would be expected to operate roughly 158 / 422 = 37% per year.

While RIE completed the calculations for purposes of this response, the Company does not suggest that a calculation to estimate how often a scheme operates is meaningful. Instead, the Company suggests consideration of the goal of main line frequency reduction of 25%.

Division 4-37
Distribution Automation

Request:

Had each circuit associated with DIV-4-36 above not been part of a FLISR installation, what would be the estimated minutes of outage reduction and customer minutes of outage reduction for each circuit? Describe in detail how RIE developed those estimates and provide supporting data.

Response:

If the circuit was not associated with a FLISR scheme, then that circuit would not get the Distribution Automation program benefit of a 25% reduction in main line events.

This question may be attempting to explore what the benefits might be with a sectionalizing recloser only, avoiding a recloser at an open points. In this case, a rough approximation of the benefit would be half of the estimated 25% main line frequency reduction or a 12.5% reduction. This rough approximation is simply derived from recognition that for downstream faults of a new sectionalizing recloser, the upstream customers would avoid an interruption.

Division 4-38
Distribution Automation

Request:

Based on the actual number of operations and outage minutes reduced from the approximately 20 reclosers recently installed by RIE, what was the actual average minutes of outage reduction, the customer minutes reduced and the reliability statistic improvement for each associated feeder? Provide the time period analyzed and list for both blue-sky and storms. Confirm that reclosers do not have a FLISR scheme.

Response:

The table shown on the next page summarizes the actual minutes of outage reduction, the customer minutes reduced and the reliability statistic improvement for each feeder associated with the approximately 20 reclosers that were recently installed. All the events that are shown in the table occurred during blue-sky weather and all events were reviewed dating back to April 1, 2022. No reclosers on the RIE system currently have an automated FLISR scheme. One of the new reclosers installed at pole 64 Central St in Pawtucket has been programmed for a voltage sensing loop scheme. This scheme works in conjunction with other reclosers installed on adjacent feeders to automatically sense a loss of voltage and automatically switch to the supply with healthy voltage. This is not considered a FLISR scheme.

Rows that contain reclosers that were installed either on or after April 1, 2022, but have not operated, are identified with N/A.

Please note that bolded rows in the table below had events where the recloser operated.

Division 4-38, page 2

Distribution Automation

PTR Location	PTR Location	Feeder	# of Customers	Outage Minute Reduction	CMI Reduction	CKAIFI Reduction	CKAIDI Reduction
P82-50 W. Main Rd. Portsmouth	Midline	36W44	N/A	N/A	N/A	N/A	N/A
P5 State St. Bristol	**Tie**	**51F2**	**3727**	**30 min**	**55,230 min**	**.494**	**14.8 min**
P118 Smithfield Ave Lincoln	**Tie**	**102W52**	**2232**	**56 min**	**82,488 min**	**None**	**56 min**
P250 Smith St. North Providence	Tie	13F9/ 69F1	N/A	N/A	N/A	N/A	N/A
P165-50 Diamond Hill Rd. Cumberland	**Tie**	**126W41**	**2373**	**1.58 min**	**3,087 min**	**.8217**	**1.30 min**
P165-50 Diamond Hill Rd. Cumberland	**Tie**	**126W41**	**2373**	**56.6 min**	**135,730 min**	**None**	**57.2 min**
P165-50 Diamond Hill Rd. Cumberland	**Tie**	**102W54**	**2307**	**56.5 min**	**131,419 min**	**None**	**56.5 min**
P74 Power Rd Pawtucket	Tie	107W80/ 107W63	N/A	N/A	N/A	N/A	N/A
P43 Victory Hwy Coventry	Tie	54F1/ 63F6	N/A	N/A	N/A	N/A	N/A
P64 Central Ave Pawtucket	**Tie**	**1201W5**	**2787**	**60 min**	**167,220 min**	**.619**	**60 min**
P64 Central Ave Pawtucket	**Tie**	**1201W6**	**3329**	**60 min**	**205,221 min**	**.6008**	**61.7 min**
P15-50 Martin St. Cumberland	**Tie**	**126W51**	**1732**	**57 min**	**122,550 min**	**None**	**70.8 min**
P2 Tupelo St. Bristol	Tie	5F3/5F4	N/A	N/A	N/A	N/A	N/A
P213 Shore Rd. Westerly	**Tie**	**16F1**	**2067**	**53 min**	**111,365 min**	**None**	**54.1 min**
P1 Metcalf Ave North Providence	Midline	69F1	N/A	N/A	N/A	N/A	N/A
P5 Longvue Ave Westerly	Tie	16F4/ 155F4	N/A	N/A	N/A	N/A	N/A
P51 Oak St. Hopkinton	Midline	155F4	N/A	N/A	N/A	N/A	N/A
P5 River St. Woonsocket	Midline	108W62	N/A	N/A	N/A	N/A	N/A
P77 Tollgate Rd. Warwick	Midline	14F3	N/A	N/A	N/A	N/A	N/A
P255 Chalkstone Ave Providence	Midline	69F3	N/A	N/A	N/A	N/A	N/A
P26 Randall St. Pawtucket	**Midline**	**107W61**	**2379**	**30 min**	**39,900 min**	**.1871**	**46.8 min**
P33 Log Bridge Rd. Coventry	Midline	54F1	N/A	N/A	N/A	N/A	N/A

Division 4-39
Distribution Automation

Request:

RIE states that certain FLISR recloser actions will result in an approximate 2 minute momentary interruption (page 130). How many times would this occur over a 20-year period and how did the Company derive that estimate?

Response:

The two-minute momentary interruption would occur any time an upstream fault occurred near a recloser in a FLISR scheme. The two-minute time period is the time for the FLISR algorithm to process and communicate with the main line recloser to open and the recloser at the tie point to close. It was derived from discussions with subject matter experts at PPL Corporation.

Referencing the response to Division 4-36, the 2 minute interruption could occur 0.37* 20 years = 7.4 times, although this calculation does not have any measurable correlation to reliability.

Division 4-40
Distribution Automation

Request:

RIE provides a table of potential circuits and number of reclosers in Figure 11 (page 131) where 93 circuits are shown to exceed the RI regulatory SAIFI threshold of 1.05. RIE proposes 336 reclosers on those circuits. In addition, RIE "has included additional high thresholds to facilitate vary cash flow scenarios" (page 131) This results in an additional 447 proposed reclosers on 115 circuits which would cost over $35 million (at $80,000 per recloser). Why does RIE believe that targeting circuits with SAIFI as low as 0.5 is a cost effective strategy to maintain what is already excellent reliability? Why does RIE need to invest $35 million on circuits that are not experiencing poor reliability performance and are not proven to require additional investments otherwise?

Response:

RIE believes that customers' expectations regarding reliability are changing and that as a result performance that may appear excellent as compared to regulatory thresholds may be considered poor by current customers' expectations. The Company has and continues to gather information regarding customer experience and how RIE compares against its peers to further evaluate this trend. The Company has put forward a programmatic approach. Accordingly, its proposal within the program to address circuits with frequencies less than 1.05 is two to three years away, and the Company will continue to evaluate the need for and appropriate number of reclosers on those circuits. The Company expects continued discussions with the Division and the requirement to demonstrate actual performance, to support execution of future program years

Division 4-41
Distribution Automation

Request:

Why does the Company propose up to nine reclosers on a single circuit (pp 133-135)? How can nine reclosers on a circuit be appropriately coordinated? Has RIE completed this coordination analysis to determine if it is reasonable?

Response:

The Company is not proposing the installation of 9 mainline reclosers in series that will be required to appropriately coordinate with each other. Attachment A of the Distribution Automation Recloser Program documentation on pp 133–135 provides an approximate number of reclosers to be installed. The reclosers in Attachment A include, Mainline Reclosers, not necessarily in series, which are normally closed and installed along a distribution circuit with upstream and downstream customers and Tie Reclosers which are normally open and installed at a tie point between two distributions circuits.

The number of reclosers in the program documentation were estimated to develop the potential scope and cost of the program. Final recloser locations will be determined at the commencement of the program and will follow the guidelines outlined in Section 4.3 of the program documentation, pp. 127–128. The coordination analysis will be complete once device locations are identified and prior to construction.

Division 4-42
Distribution Automation

Request:

If a sectionalizing device such as a fault saver costs $10,000 installed and a simple recloser installation costs $20,000 to $30,000 why would an $80,000 to $90,000 recloser at every installation be economically justifiable or make engineering sense?

Response:

Reclosers are not recommended at locations where fault savers are appropriate. See the response to Division 3-21, Attachment DIV 3-21-2. The term "simple recloser" is not a standardized industry term, and the Company therefore cannot say with certainty what functionalities the Division envisions the simple recloser would have. That said, the Company expects that the simple recloser posited in the question would not include high accuracy current and voltage sensing on all three phases, line and load side, as required by today's distribution system with moderate to high DER penetration. The Company also expects that the simple recloser would not contain functionality to include dynamic protection settings, high impedance fault detection, communication capabilities, or other functions, which could lead to high probability of early obsolescence. The Company has taken a measured approach that has evolved over the course of a decade in development of its standard recloser, which does include these functionalities. In addition to fundamental engineering sense, considering value and function, the reclosers are economically justified as demonstrated by the benefit-cost analysis shown in the program documentation (pages 128 to 130).

Prepared by or under the supervision of: Ryan Constable

Division 4-43
Distribution Automation

Request:

Provide a list of each circuit proposed for work under the Distribution Automation program in FY 2025 with the information below. Provide accompanying tables and spreadsheets in executable format:

a. Substation name, voltage, miles of line and customers served by customer class.
b. Analysis relied upon to select the circuits including a discussion of how locations have been prioritized. Provide all underlying data to support the selections.
c. Circuit map showing:
    i. the location of each outage for the previous 5 years (or the timeframe used in selection analysis-please indicate)
    ii. the specific location for each recloser
    iii. number of customers served by each sectionalized line segment.
d. For the previous five years (or the timeframe used in selection analysis-please indicate), reliability statistics for each proposed feeder. Include outages, by cause, separated by non-storm and storm.
e. Expected reliability improvement on a feeder and system basis.
f. How proposed reclosers act as a sectionalizing point and a self-healing circuit configuration (FLISR).
g. Full project scope, timeline and costs. Where FLISR will be incorporated, include all components such as reclosers, current or future required substation upgrades (relay replacements or setting changes, or added capacity), distribution line upgrades to accommodate the FLISR design and load transfer capacity capability (additional ties, reconductoring, etc.), communications system additions such as mesh network and fiber, and any other software or systems.
h. A table for each of the above listed costs and monthly schedule for completion.
i. A timeline of initial recloser installation and ultimate FLISR functionality.
   Program cash flows are delineated in the program documentation with in the Proposed FY25 ISR plan, See Figure 12, Attachment 6 on page 132.
j. Confirmation of system protection and coordination.

Prepared by or under the supervision of: Ryan Constable

Division 4-43, page 2
Distribution Automation

k. A discussion of how work will maximize efficiencies and be coordinated with Area Study work in progress or planned.

Response:

The Company provided the following information on Attachment DIV 4-43-1 file for circuit selected for the Distribution automation recloser program:

a. Substation name, voltage, miles of line and customers served.

b. Analysis relied upon to select the circuits including a discussion of how locations have been prioritized. Provide all underlying data to support the selections.

Data used to select circuit is shown in Attachment DIV 4-43-1 file tab 'FY25 DA Circuit List' See colunm lables b.3 through b.16 of the spreadsheet.

See page 125 of the proposed FY 2025 Electric ISR plan Attachment 6, Section 4.2 'Circuit Selection Criteria' for a discussion on how circuits were prioritized. Recloser placement prioritization is discussed in Section 4.3 'Determining Recloser Placements on Circuits' of the same Attachment starting on page 127.

c. Circuit map showing:
   i. the location of each outage for the previous 5 years (or the timeframe used in selection analysis-please indicate)
   ii. the specific location for each recloser
   iii. number of customers served by each sectionalized line segment.

   As described in DIV 3-22 the data sets used to create outage maps (IDS outage events database) and the RIE's geographical software options (CYME or Smallword GIS) are not linked. Graphical outage maps are currently done in the planning stages of the project and are produced manually by the Field Engineer. However, sample circuit, Chase Hill Substation 155F4 is provided in the 'Maps C' tab in file DIV 4-43-1.

d. reliability statistics for each proposed feeder. Include outages, by cause, separated by non-storm and storm.

   Reliability Statistics for each proposed feeder is include in the FY25 DA Circuits Tab of companion file DIV 4-43-1. Outages are provided on the 'Outage' Tab of the same document.

Distribution Automation

e. Expected reliability improvement on a feeder and system basis.
   See 'Reliability Improvement' tab of File Attachment DIV 4-43-2.

f. How proposed reclosers act as a sectionalizing point and a self-healing circuit configuration (FLISR).

   Fault location, isolation, and service restoration (FLISR) is a distribution automation solution that automatically restores power to as many customers as possible, as quickly as possible, in the event of a permanent fault. Reclosers employed with FLISR logic minimize the impact of outages by automatically switching around the fault line sections and restoring service to otherwise healthy parts of the distribution network.

   The ADMS system is a centralized data collection hub that is capable of real-time monitoring, control, and automatic operation of connected devices such as distribution circuit breakers and line reclosers. The first action to initiate the FLISR scheme is the detection of a permanent fault on the distribution feeder. This occurs when a protective device opens intentionally. A second device located at end of faulted line sections (typically a recloser) opens, isolating compromised line section. The ADMS system then reconfigures adjacent feeders by directing a normally open recloser to close. This automatically restores customers on healthy line sections. In the absence of FLISR, the customers will remain without service until the circuit was manually isolated by a line crew or remotely switched by a system operator.

g. Full project scope, timeline and costs. Where FLISR will be incorporated, include all components such as reclosers, current or future required substation upgrades (relay replacements or setting changes, or added capacity), distribution line upgrades to accommodate the FLISR design and load transfer capacity capability (additional ties, reconductoring, etc.), communications system additions such as mesh network and fiber, and any other software or systems.

   The project scopes for each individually placed recloser have yet to be determined. It would be unexpected and premature to do so at this time, as the company is requesting the program's inclusion in the FY25 ISR budget. Implementation timelines and costs are shown in Figure 12 page 132, Attachment 6 of the Proposed FY2025 ISR.

   Incorporating Distribution Automation into RIE's electrical distribution networks requires a recloser equipped with the standard communications package. Distribution line upgrades to accommodate system capacity deficiencies are defined in the area planning studies. They are not part of the Distribution Automation Recloser program. Substation

Distribution Automation

upgrades are also not driven by this program and outside the scope. Communications upgrades to implement FLISR schemes are not required.

h. A table for each of the above listed costs and monthly schedule for completion.

   The cost and schedule are included in the program documentation in the proposed FY25 ISR filing. See Figure 12, Attachment 6, 132. It is premature to attempt monthly schedules at the time of this filing.

i. A timeline of initial recloser installation and ultimate FLISR functionality.

   The timeline of the initial recloser installation is shown in page 132, Figure 13, Attachment 6 of the Proposed FY25 ISR Plan. FLISR functionality is part of the recloser commissioning process and is available when the devices are placed in service. FLISR functionality within the Control Center is expected during calendar year 2024.

j. Confirmation of system protection and coordination.

   Confirmation of system protection and coordination is done during final design, just prior to deployment. It would be premature to produce protection settings before final design details are determined.

k. A discussion of how work will maximize efficiencies and be coordinated with Area Study work in progress or planned

   Area Study work has been considered in the Distribution Recloser Program. The circuit selection process, described fully on page 125, 4.2 Circuit Selection Criteria, Attachment 6 of the Proposed FY25 ISR plan, includes a construction adder for circuits with eminent construction projects. This gives the company an opportunity to gain design, material procurement, outage planning, and construction efficiency. Given that the company's capital construction schedule can be dynamic, construction adders will be revised annually to match the planned work schedule.

Attachments DIV 4-43

The Company provided the Excel files of Attachment DIV 4-43-1 and Attachment DIV 4-43-2.

Prepared by or under the supervision of: Ryan Constable

Division 4-44
Distribution Automation

Request:

The distribution automation program is designed over 5 years (page 122). Provide a table for the entire plan and a feeder map for each recloser or set of reclosers per feeder. If circuit selections and associated work have not been identified beyond the FY 2025 ISR Plan year, indicate when that analysis will occur and be presented for Division review.

Response:

Circuit selections have not been identified beyond the FY 2025 ISR Plan year. This is a common practice within any program, to identify the subject work in advance of the pending fiscal year and ISR Plan proposal. In this manner, the programs can adjust to changing conditions such as other work that may accelerate or delay specific locations under the program.

The Division will be presented with each fiscal year's circuit selections in the late Summer or early Fall prior to the start of the fiscal year. Detailed recloser information, such as maps showing recloser locations, can be provided at a later date, prior to work execution after engineering and design activities. These engineering and design activities will be staggered across any fiscal year to facilitate work execution. The Company is receptive to discussions to establish a review of the recloser locations after design and prior to the work.

Andrew S. Marcaccio, Counsel
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280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

December 4, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 5

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's response to the Division of Public Utilities and Carriers' Fifth Set of Data Requests in the above-referenced matter.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

Division 5-1

Request:

To the extent not provided in response to DIV-2-19, please provide all updated CYME models for the RIE system.

Response

The Company is attaching the CYME models in a zip file, containing 11 study files, which is being provided via a separate link.

Prepared by or under the supervision of: Ryan Constable

Andrew S. Marcaccio, Counsel
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Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

December 20, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 6</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's response to the Division of Public Utilities and Carriers' Sixth Set of Data Requests in the above-referenced matter.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Shultz, Esq.
Christy Hetherington, Esq.
John Bell, Division
Greg Booth, Division
Al Contente, Division

Division 6-1

Request:

Regarding the Company responses to DIV 1-4 & 1-5: RIE indicates that the area study based on extreme summer peak has not been reached and no new CYME models will be performed at this time. When and how will the AMF data be incorporated into the CYME models to establish a better feeder profile? Does AMF data provide better visibility and feeder profile intelligence than data collected at discrete points on feeders?

Response:

The AMF data will be incorporated into the Company's analysis as soon as possible. The Company expects that AMF data will first be incorporated into the Control Center's pending ADMS Powerflow Application. Somewhat in parallel but staggered to incorporate learnings form the real time Powerlflow effort, the Company will incorporate AMF data into the CYME models. Incorporating the data is expected to happen in stages. For instance, subsets of the AMF data may be initially incorporated to handle the increasing data magnitude, methods developed to efficiently incorporate this increased data, and then this step-wise process repeated until the full AMF data set is included. This process will start after AMF deployment is completed, but there is not a set date for fully incorporating AMF data into the Company's analysis tools at this time.

AMF data will provide increased visibility and feeder profile intelligence than currently available and when used in conjunction with device data at discrete points on feeders, it provides significantly improved visibility and profile intelligence. AMF data does provide better visibility and feeder profile intelligence than data collected at discrete points on feeders, however the devices that provide the discrete point data provide operational functionality.

The pending AMF data requirements add further justification to the Company's statement in Division 1-5 that, "The Company does note that as the distribution system becomes more complex, there will be a need for yearly, monthly, weekly, and even daily loadflow model updates. The need for advanced tools and data processing to achieve this functionality is noted within the Company's Grid Modernization Plan."

Prepared by or under the supervision of: Ryan Constable

Division 6-2

Request:

Please further expand the Company's response to DIV 1-10 by indicating how the forecasted load is distributed across a circuit. Is the distribution transformer kVA used to ratio the forecasted load or is the customer kWh used or some other methodology? What non-coincidence factors are used to ratio system forecast demand to feeder and customer demand?

Response:

Within the CYME software there are a number of allocation methods. The planners typically use an actual kWh or KVA allocation method where the 'actual' data is extracted from the Company's Geographic Information System (GIS) system. The actual kWh data comes from the meter system to the GIS system, accumulated to a service transformer level, and then is extracted to the CYME model. The 'actual' KVA is a calculation based on the kWh and an average load cycle. A connected KVA allocation method is sometimes used when the previous methods do not converge or provide incorrect results.

Actual feeder peak loads are used for the allocation. Since the purpose of the analysis is a feeder level review, using feeder peaks is appropriate. Coincidence factors between the feeder and system peaks are not necessary. When using an allocation method, calculation of coincidence factors between the feeder peaks and customer peaks are not necessary.

Division 6-3

Request:

Regarding response to DIV 1-11, define or provide examples of "proper software tools" that eliminate the need to use approximation methods to allocate peak loads. When is RIE is expected to implement the software tools? How will AMF data be incorporated and used to distribute load across feeders? Will these tools replace CYME, or be used in addition to CYME? Are these tools used or planned in other PPL jurisdictions?

Response:

A "proper software tool" is a tool that can locationally incorporate yearly time-stamped AMF data and other device data and process that data across a multi-year period in a reasonable time. RIE has tested a current version of CYME, and while CYME can include load profiles and detailed customer or service transformer information, processing the data across multiple years would often stall or not converge. The Company is exploring further software capabilities, computing power capabilities, and data storage and handling capabilities and presents timelines within its Grid Modernization Plan (GMP). AMF data incorporation is described in the response to Division 6-1. The Company expects that the software tool will be an enterprise advanced version of CYME and would be coordinated with other PPL jurisdictions.

Division 6-4

Request:

Please provide the most recent copy of the Company's Distribution Area Planning Study Process indicating any revisions from the previous version including how RIE is implementing stated improvements to project estimating when recommended plans are developed by study engineers.

Response:

The Company's Distribution Area Planning Study Process document has not been revised from the version presented in Attachment 1-35-1 to FY 2024 Division 1-35.

Prepared by or under the supervision of: Ryan Constable

Division 6-5

Request:

Regarding the Verizon Copper to Fiber project, provide for the distribution capital portion:

a. A comparison of sanctioned amounts, ISR Plan budget and actual spend by year.
b. The number of sites planned and completed each year.
c. Number of proposed sites planned by year, and anticipated project closure.

Response:

a. Please see the table below is a comparison of sanctioned amounts, ISR Plan budget and actual spend by year:

FY	Total Sanctioned Amount (000s)	ISR Plan Budget (000s)	Actual Spend (000s)
FY 2021	240	-	27
FY 2022	1,000	800	160
FY 2023	1,000	1,000	86
FY 2024	0	1,000	42

b. Please see the table below for the number of sites planned and completed each year.

	FY 2021	FY 2022	FY 2023	FY 2024
Planned	25	25	25	25
Completed	5	5	6	6 (to date)

When this project was initially sanctioned it was expected that Verizon would be progressing with the conversion of approximately 25 Distribution stations per year. The number of stations completed per year are completely influenced by Verizon's schedule.

Note: Blackburn, and Pontiac were not completed as the upcoming transition from National Grid EMS to PPL DMS will negate the need to transition to third party fiber service for these sites and alleviates the cost burden to the rate payers. The new system utilizes cellular services or privately owned fiber for many sites.

c. RIE is initially transitioning to a cellular based EMS system to align with the systems used in PA. This standardization will cause the future needs for copper to fiber conversions to be reduced to only include protective circuits such as DTT which is typically used to protect DER assets and other complicated generation interconnects. The Company has decreased the budgets for future years due to the decrease in work and costs coming in lower than budgeted in prior years.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

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Division 6-6

Request:

Does the Company's response to DIV 1-22 indicate that RIE can include a project in the ISR Plan without corporate approval? Explain.

Response:

No. Prior to submitting a proposed ISR plan to the Division of Public Utilities and Carriers to commence the statutory 60-day consultation period and filing a proposed ISR plan with the Public Utilities Commission for approval, the projects and programs that form the proposed budget for that fiscal year plan undergo multiple reviews with internal stakeholders, including with the President of Rhode Island Energy. The Company's management team also reviews the proposed projects and programs through Study and Program Documentation that are created for certain investments. Please see Bates pages 19-21 of the Company's proposed FY2025 Electric ISR Plan for an explanation regarding the development of the work plan and estimating. Please see Bates page 22 of the Company's proposed FY2025 Electric ISR Plan for an explanation regarding delegation of authority and sanctioning.

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

Division 6-7

Request:

To the extent not provided under another data request, provide the Engineering Reliability Reviews conducted on the Tiverton 56-33F3 and 56-33F4 feeders in FY20.

Response:

Please see the Engineering Reliability Reviews for FY20:

- Tiverton 56-33F3 (Attachment DIV 6-7-1)
- Tiverton 56-33F4 (Attachment DIV 6-7-2)

nationalgrid

Memorandum

To: Kathy Castro

From: Robert Wilcox

Date: 09/30/2019

Subject: Problem and Poor Performing Reliability Review for feeder Tiverton 56-33F3

This memo documents the recommendations to improve both CKAIFI and CKAIDI on the 2018 NECo Circuit **Tiverton 56-33F3**.

RELIABILITY PERFORMANCE

The following tables show the historical reliability performance and the predicted performance improvement after recommendation in this document are completed.

			CKAIFI Performance History by Year					5 Year Average CKAIFI After Proposed Improvements		
CKAIFI Feeders	2018 Cust. Served	5 Year Average CKAIFI	2018	2017	2016	2015	2014	Pending Work	Short Term Work	Long Term Work
56-33F3	3,544	1.242	0.565	1.528	1.851	1.543	0.820	N/A	1.22	N/A

			CKAIDI Performance History by Year					5 Year Average CKAIDI After Proposed Improvements		
CKAIDI Feeders	2018 Cust. Served	5 Year Average CKAIDI	2018 (min.)	2017 (min.)	2016 (min.)	2015 (min.)	2014 (min.)	Pending Work	Short Term Work	Long Term Work
56-33F3	3,544	110.46	53.52	101.61	127.64	194.73	92.29	N/A	106.88	N/A

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit: Tiverton 56-33F3

Date	Year	Protective Device Type	Protective Device Pole	Protective Device Town	Cause	Failed Component	Classification	SAIFI	SAIDI (min)
02/02/2014	2014	Recloser	P405 MAIN	TIVERTON	Insulation failure - other	Insulator - pin or post	Main line - overhead	0.503	53.21
04/17/2015	2015	Solid disc - main	P88 LONG	LITTLE COMPTON	Unknown	Conductors	Main line - overhead	0.146	7.93
08/12/2015	2015	Station breaker	Circuit Breaker	TIVERTON	Vehicle	Pole - wood	Main line - overhead	1.17	157.32
01/15/2016	2016	Recloser	P405 MAIN	TIVERTON	Device Failed	Overhead Device Other	Main line - overhead	0.504	22.03
01/23/2016	2016	Recloser	P115 EAST	TIVERTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.173	22.10
02/20/2016	2016	Station breaker	Circuit Breaker	TIVERTON	Vehicle	Pole - wood	Main line - overhead	0.999	65.95
04/25/2017	2017	Fused disc - branch	P333 WEST MAIN	LITTLE COMPTON	Other Company Activities	No failure or Unknown	Fused branch - overhead	0.119	0.71
06/06/2017	2017	Recloser	P405 MAIN	TIVERTON	Tree Fell	No failure or Unknown	Main line - overhead	0.753	37.65
08/18/2017	2017	Recloser	P115 EAST	TIVERTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.139	15.51
09/21/2017	2017	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.2	8.21
09/22/2017	2017	Recloser	P115 EAST	TIVERTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.138	13.55
09/12/2018	2018	Recloser	P163 MEETINGHOUSE	LITTLE COMPTON	Tree Fell	No failure or Unknown	Main line - overhead	0.299	5.68

COMPLETED WORK

Replaced 40K Fuse at P95 East Rd. with Cutout mounted Recloser, January 2017.

Replaced 3 Phase Regulator at Pole 61 West Main Rd. with 3 – 1 Phase regulators at Poles 70, 72, and 73, October 2017.

Replaced 100K Fuse at Pole 2725 Lake Rd. with Cutout Mounted Recloser.

PENDING WORK

Install Radio Recloser Control for Pole-top Recloser at Pole 163 Meeting House Ln.

Replace Recloser Pole 405 Main Rd.

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Benefits for the short-term recommendations are shown in the reliability tables on page 1.

Tree Trimming: Not Recommended

The 33F3 was last trimmed in FY 2019. There is not enough information to know if the cycle prune has improved reliability. There have been 8 Tree related events since November 1, 2018, accounting for 8 events, 157 Customers Interrupted, and 9,071 CMI. No additional trimming is recommended at this time.

Infrared Circuit Scan: Recommended

The Previous IR scan was completed in September 2012. There are a number of Deterioration related events beyond the Recloser at Pole 252 West Main Rd. If the entire circuit can not be scanned, it is recommended to have a partial scan beyond this recloser. If there were no deteriorated equipment failures beyond this recloser, SAIFI would be reduced by 0.022, and SAIDI would be reduced by 3.576 minutes.

Animal Mitigation: Not Recommended

Animals account for less than 10% of Events, and less than 2% of CI, and CMI over the past 5 years, therefore, no animal mitigation is required.

Fault Indicators: Not Recommended

There are no major Bifurcation points on this circuit that do not have either fuses or reclosers, therefore, no fault indicators are recommended.

Load Balancing: **Not Recommended**

There is no significant Load imbalance on the 33F3 circuit. The table below is the peak loading on the 33F3 circuit.

Location	Reading Type	Amps			
		A Phase	B Phase	C Phase	Ground
33F3 Breaker	Pi	304	365	322	54
P405 Main Rd. (SW# 624049)	Pi	162	176	213	46
P163 Meetinghouse Ln. (SW# 625006)	Pi	48	44	42	5
P115 East Rd. (SW# 624038)	Cyme	75	56	67	17
P252 W Main Rd. (SW# 625009)	Cyme	49	79	37	37

Cutout Mounted Recloser Installations: **Not Recommended**

None of the Fuses on the 33F3 circuit has experienced more than 3 operations, with the exception of P95 East Road, which has had 7. Of those 7, 3 were Tree Fell events, that would have been permanent. Therefore, there is no recommendation for installing CMR's on this circuit.

Line Recloser Installations (include Form3s): **Not Recommended**

The 33F3 currently has 4 reclosers. There are no more viable locations for reclosers on this circuit.

Additional Circuit Sectionalizing: **Not Recommended**

Outages on this circuit tend to be well distributed across the entire circuit, and no devices tend to operate more often than others. No addition sectionalizing is recommended.

Additional Feeder Ties/Reconfiguration: **Not Recommended**

The 33F3, according to the Annual Plan, currently fails the 16 MWHr Criteria at 18.6 MWHrs. Tiverton is the only 12.47kV substation in this area, so there are no additional feeder ties available. In the long term, converting this substation to 13.8kV would allow for feeder ties to the MECo feeders nearby.

Protective Device Coordination Review: **Not Recommended**

A DG study was completed on this feeder in the past year. After reviewing the ASPEN file from this study, in both the existing, and proposed states, there is no need for a detailed device coordination review.

Short Term Recommendation – Cost Summary

Funding Project #	STORMS Code	Title/Description	$ Cap	$ O&M	$ Rem	$ Total
	ERR2018RI	None				

LONG TERM SYSTEM IMPROVEMENTS

No Long-Term System Improvements are recommended at this time.

nationalgrid

Memorandum

To: Kathy Castro

From: Robert Wilcox

Date: 09/30/2019

Subject: Problem and Poor Performing Reliability Review for feeder Tiverton 56-33F4

This memo documents the recommendations to improve both CKAIFI and CKAIDI on the 2018 NECo Circuit **Tiverton 56-33F4**.

RELIABILITY PERFORMANCE

The following tables show the historical reliability performance and the predicted performance improvement after recommendation in this document are completed.

			CKAIFI Performance History by Year					5 Year Average CKAIFI After Proposed Improvements		
CKAIFI Feeders	2018 Cust. Served	5 Year Average CKAIFI	2018	2017	2016	2015	2014	Pending Work	Short Term Work	Long Term Work
56-33F4	2,797	2.165	0.725	2.180	3.687	3.478	0.725	N/A	1.38	N/A

			CKAIDI Performance History by Year					5 Year Average CKAIDI After Proposed Improvements		
CKAIDI Feeders	2018 Cust. Served	5 Year Average CKAIDI	2018 (min.)	2017 (min.)	2016 (min.)	2015 (min.)	2014 (min.)	Pending Work	Short Term Work	Long Term Work
56-33F4	2,797	234.91	73.15	176.19	520.17	304.45	68.47	N/A	149.17	N/A

Summary of Significant Outage Events
(Significant contribution to CKAIFI is >=.1 or for CKAIDI is >= 30 min)

Circuit: Tiverton 56-33F4

Date	Year	Protective Device Type	Protective Device Pole	Protective Device Town	Cause	Failed Component	Classification	SAIFI	SAIDI (min)
03/30/2014	2014	Recloser	P733 COLEBROOK	LITTLE COMPTON	Device Failed	Overhead Device Other	Main line - overhead	0.35	20.25
07/15/2014	2014	Fused disc - branch	P21 RIVER	WESTPORT	Tree Fell	No failure or Unknown	Fused branch - overhead	0.107	11.90
06/23/2015	2015	Recloser	P2 CRANDALL	TIVERTON	Lightning	Tap	Main line - overhead	0.793	18.23
10/29/2015	2015	Station breaker	Circuit Breaker	TIVERTON	Tree Fell	No failure or Unknown	T or D Supply - above 69 KV	1.003	107.31
12/22/2015	2015	Recloser	P2 CRANDALL	TIVERTON	Device Failed	Switch Loadbreak	Main line - overhead	0.744	100.25
01/12/2016	2016	Recloser	P2 CRANDALL	TIVERTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.791	98.92
01/17/2016	2016	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree Fell	No failure or Unknown	Main line - overhead	0.353	48.73
01/19/2016	2016	Recloser	P719 OLD HARBOR	LITTLE COMPTON	Tree Fell	Conductors	Main line - overhead	0.144	14.08
07/13/2016	2016	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree Fell	Conductors	Main line - overhead	0.386	21.37
07/23/2016	2016	Recloser	P733 COLEBROOK	LITTLE COMPTON	Lightning	No failure or Unknown	Main line - overhead	0.352	112.29
08/04/2016	2016	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree Fell	Conductors	Main line - overhead	0.352	22.26
08/12/2016	2016	Recloser	P2 CRANDALL	TIVERTON	Lightning	Insulator - pin or post	Main line - overhead	0.787	148.78
10/09/2016	2016	Fused disc - branch	P21 RIVER	WESTPORT	Tree - Broken Limb	No failure or Unknown	Fused branch - overhead	0.193	15.80
01/12/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Tree - Broken Limb	No failure or Unknown	Fused branch - overhead	0.106	6.28
09/20/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Tree - Broken Limb	No failure or Unknown	Fused branch - overhead	0.177	8.31
09/21/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Tree Growth	No failure or Unknown	Fused branch - overhead	0.137	16.39
09/21/2017	2017	Recloser	P2 CRANDALL	TIVERTON	Tree Fell	No failure or Unknown	Main line - overhead	0.737	48.61
09/21/2017	2017	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.188	7.70
11/19/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Tree Fell	No failure or Unknown	Fused branch - overhead	0.11	7.35
11/21/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Unknown	No failure or Unknown	Fused branch - overhead	0.107	9.19
12/09/2017	2017	Fused disc - branch	P21 RIVER	WESTPORT	Vehicle	Pole - wood	Fused branch - overhead	0.177	15.77
03/14/2018	2018	Solid disc - main	P3 COLEBROOK	LITTLE COMPTON	Deterioration	Crossarm	Main line - overhead	0.132	2.91
09/18/2018	2018	Recloser	P733 COLEBROOK	LITTLE COMPTON	Tree - Broken Limb	No failure or Unknown	Main line - overhead	0.189	10.02

COMPLETED WORK

Install 40K Fuse Pole 19 Long Hwy, March 2015.
Replace Recloser Pole 2 Crandell Rd., October 2016.
Install Fault Indicators at various locations, February 2018.
Replace 65K Fuse at Pole 57 Crandall Rd., June 2018.
Install Recloser Radio, September 2018.

PENDING WORK

URD Cable Replacement, Replace 3500 feet of 1/C #2 XLPE direct buried cable, Pequaw Honk Dr., Little Compton, RI. Cost Estimate: $612,500 – Funding Project C076289.

RECOMMENDATIONS

SHORT TERM

Due to the low cost of the short-term recommendations, no alternative analysis is considered. The recommended plan is the least cost option. Benefits for the short-term recommendations are shown in the reliability tables on page 1.

Tree Trimming: **Recommended**

The 33F4 was last trimmed in FY 2017, and is scheduled to be trimmed again in FY 2021. In the years prior to trimming the 33F4 trees averaged 12 events (41% of all events), 4,303 Customers Interrupted (52% of Total Customers Interrupted), and 449,651 CMI (46% of Total CMI). In 2017 trees accounted for 28 events (58% of all events), 4,839 Customers Interrupted (80% of Total Customers Interrupted), and 362,949 CMI (74% of Total CMI). In 2018 trees accounted for 18 events (49% of all events), 1,189 Customers Interrupted (59% of Total Customers Interrupted), and 118,004 CMI (58% of Total CMI).

Even though trees continue to be a significant portion of the reliability of this circuit, there has been a significant reduction in the impact of trees on this circuit in the past year. For the portion of this circuit in RI, the cycle prune scheduled for this circuit should be sufficient. The MA potion of the circuit continues to be trouble for this circuit. There are 2 fuses at poles 16 and 21 River Road, that account for 21 tree events in 2017 and 2018, causing 4,245 Customers interrupted, and 386,384 CMI. This portion of the circuit requires trimming.

Infrared Circuit Scan: **Not Recommended**

The Previous IR scan was completed in September 2012. Deterioration, and Transformer overload are not significant contributors to poor reliability on this circuit, and a prioritized IR scan is not necessary.

Animal Mitigation: **Not Recommended**

Animals account for less than 2% of Events, CI, and CMI over the past 5 years, therefore, no animal mitigation is required.

Fault Indicators: **Not Recommended**

There are no major Bifurcation points on this circuit that do not have either fuses or reclosers, therefore, no fault indicators are recommended.

Load Balancing: **Recommended**

There is a significant imbalance on the recloser at Pole 2 Crandall Rd. The table below is the peak loading on the 33F4 circuit.

Location	Reading Type	Amps			
		A Phase	B Phase	C Phase	Ground
33F4 Breaker	Pi	520	461	505	53
P2 Crandall Rd. (SW# 624055)	Pi	394	280	362	102
P719 Old Harbor Rd. (SW# 625002)	Pi	64	68	90	24
P733 Main St. (SW# 625020)	Cyme	112	72	58	49

It is recommended to make the following reconfigurations to balance the 33F4:

Move Tap from A Phase to B Phase P22 Long Hwy.

Move Tap from B Phase to A Phase P55 Bulgarmarsh Rd.

After Balancing the peak loading would be:

Location	Reading Type	Amps			
		A Phase	B Phase	C Phase	Ground
33F4 Breaker	Pi	478	503	501	24
P2 Crandall Rd. (SW# 624055)	Pi	330	337	362	29
P719 Old Harbor Rd. (SW# 625002)	Pi	64	70	88	22
P733 Main St. (SW# 625020)	Cyme	66	117	56	57

Cutout Mounted Recloser Installations: **Recommended**

Frank Carro recommended 2 Cutout Mounted Reclosers to be installed on this circuit. Both were on the MA portion of this circuit. One was to be located at P128 River Rd., Westport, MA, and the second at P24 Howland Rd., Westport, MA. These were rejected as they are in MA. These two CMR's would save on average 125 CI and 5,730 CMI per year. It is recommended that these two CMR's be installed as recommended.

Line Recloser Installations (include Form3s): **Not Recommended**

The 33F4 currently has 3 reclosers. There are no more viable locations for reclosers on this circuit.

Additional Circuit Sectionalizing: **Not Recommended**

Outages on this circuit tend to be well distributed across the entire circuit, and no devices tend to operate more often than others. No addition sectionalizing is recommended.

Additional Feeder Ties/Reconfiguration: **Not Recommended**

The 33F4, according to the Annual Plan, currently fails the 16 MWHr Criteria at 23.6 MWHrs. Tiverton is the only 12.47kV substation in this area, so there are no additional feeder ties available. In the long term, converting this substation to 13.8kV would allow for feeder ties to the MECo feeders nearby.

Protective Device Coordination Review: **Not Recommended**

A DG study was completed on this feeder in the past year. After reviewing the ASPEN file from this study, in both the existing, and proposed states, there is no need for a detailed device coordination review.

The 65K Cutout at Pole 1 Adamsville Rd., Westport, MA is undersized. According to Cyme, there is 89A of load on this branch, and 638kVA Connected. It is recommended to replace this fuse with a 100K fuse for load and inrush purposes.

Other Recommendations: **Recommended**

The portion of the 33F4 in Westport, MA is consistently a difficult area. RI tree pruning will not trim this area, and MA doesn't see this as a MA feeder, and will not trim. It is recommended to create a new feeder designation for this area of the circuit that is part of Massachusetts Electric. It is recommended to remove the recloser at P 719 Westport Harbor Rd., and install a new recloser on a new pole between Poles 9 and 10 Old Harbor Rd., and designate this as a circuit breaker for a new feeder. This will improve SAIFI by 0.647, and the SAIDI by 67 minutes, and improve the reliability for the Westport, MA customers, by giving them visibility again.

Short Term Recommendation – Cost Summary

Funding Project #	STORMS Code	Title/Description	$ Cap	$ O&M	$ Rem	$ Total
C076289		Pequaw Honk URD Cable Replacement				612,500
	ERR2018RI	Replace 65K Fuse with 100K at P1 Adamsville	1000	200	300	1500
	ERR2018RI	Move Southern Westport Branch to MECo	86,000	2,000	4,000	92,000

LONG TERM SYSTEM IMPROVEMENTS

No Long-Term System Improvements are recommended at this time.

Division 6-8

Request:

RIE has included a placeholder for Advanced Metering Functionality (AMF) spend in FY 2025 (page 40). The Company has excluded AMF spend in the Long Range Plan (page 118). In executable format, provide a revised Long Range Plan with a line item of forecasted AMF spend based on the PUC's authorized capital in Docket 22-49-EL (described in the 9-27-23 Open Meeting Motions and Votes). To this, please add forecasted plant additions placed in service for each year of the Long Range Plan. Provide the total for each spending rationale and separately for AMF.

Response:

Please see Attachment DIV 6-8 in Excel format for the requested information. Please note, the values provided in Attachment DIV 6-8 align with Attachment 5 – Long Range Plan within the filing.

Prepared by or under the supervision of: Ryan Constable and Phil Walnock

Attachment DIV 6-8

The Company also provided the Excel version of Attachment DIV 6-8.

Jurisdictional Spotlight	2024 ISR Total Budget	2025 ISR Total Forecast	2026 ISR Forecast	2027 ISR Forecast	2028 ISR Forecast	2029 ISR Forecast	2030 ISR Forecast	2031 ISR Forecast	2032 ISR Forecast	2033 ISR Forecast	2034 ISR Forecast
Budgeted and Forecasted Capital Spending											
Asset Condition Total	**47,725**	**60,604**	**69,422**	**82,738**	**47,844**	**42,480**	**41,586**	**40,303**	**43,302**	**41,163**	**41,970**
Non-Infrastructure Total	**1,700**	**1,712**	**1,724**	**737**	**750**	**764**	**786**	**810**	**834**	**859**	**885**
System Capacity & Performance Total	**20,198**	**49,600**	**94,470**	**88,732**	**70,844**	**36,952**	**30,374**	**31,286**	**32,224**	**33,191**	**34,187**
Customer Request/Public Requirement Total	**27,514**	**58,337**	**31,172**	**32,066**	**33,115**	**34,076**	**34,008**	**35,028**	**36,079**	**37,161**	**38,276**
Damage/Failure Total	**15,192**	**17,013**	**17,616**	**16,024**	**16,415**	**16,817**	**17,322**	**17,842**	**18,377**	**18,928**	**19,496**
Total Capital Spending (Excluding AMF)	**112,329**	**187,266**	**214,404**	**220,297**	**168,967**	**131,088**	**124,077**	**125,268**	**130,817**	**131,303**	**134,814**
Total Capital Spending - AMF	**-**	**51,725**	**87,846**	**8,550**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Capital Spending	**112,329**	**238,991**	**302,250**	**228,847**	**168,967**	**131,088**	**124,077**	**125,268**	**130,817**	**131,303**	**134,814**
Budgeted and Forecasted Plant Additions											
Asset Condition	32,297	58,762	67,312	80,223	46,390	41,189	40,322	39,078	41,986	39,912	40,695
Non-Infrastructure	1,650	1,660	1,672	715	727	740	763	785	809	833	858
System Capacity & Performance	11,187	48,092	91,599	86,035	68,690	35,829	29,451	30,335	31,245	32,182	33,148
Cust Req/Pub Req	27,353	56,564	30,225	31,091	32,109	33,040	32,974	33,964	34,982	36,032	37,113
Damage/Failure	16,387	16,496	17,081	15,537	15,916	16,306	16,796	17,299	17,818	18,353	18,903
Plant Additions - ISR	**88,874**	**181,574**	**207,888**	**213,601**	**163,832**	**127,104**	**120,306**	**121,461**	**126,841**	**127,312**	**130,717**
Meter Costs	-	31,631	65,313	2,595	-	-	-	-	-	-	-
Network Costs	-	5,407	7,353	2,140	-	-	-	-	-	-	-
System Costs	-	19,783	15,181	3,815	-	-	-	-	-	-	-
Program Costs	-	-	-	-	-	-	-	-	-	-	-
Plant Additions - AMF	**-**	**56,821**	**87,846**	**8,550**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Forecasted Plant Additions	**88,874**	**238,396**	**295,734**	**222,152**	**163,832**	**127,104**	**120,306**	**121,461**	**126,841**	**127,312**	**130,717**

Capital Spending
Per Chart 3 - Capital Spending by Category FY 2012 - FY 2025 (Bates 17)

	FY2019	FY2020	FY2021	FY2022	FY2023	5 Yr Total
CR/PR	$23,989	$28,667	$21,990	$34,335	$31,727	**$140,707**
D/F	13,999	17,028	19,491	20,200	17,461	**88,179**
Asset Cond	32,897	32,878	41,816	35,792	44,239	**187,621**
NI	673	145	(57)	1,100	1,554	**3,415**
SC&P	39,515	24,958	17,387	15,303	13,464	**110,627**
	$111,072	$103,676	$100,627	$106,730	$108,444	**$530,550**

Plant in Service
Per Chart 4 - Plant in Service FY 2012 - FY 2025 (Bates 18)

	FY2019	FY2020	FY2021	FY2022	FY2023	5 Yr Total
CR/PR	$24,011	$29,730	$16,761	$25,317	$27,984	**$123,803**
D/F	16,172	18,035	19,684	21,246	13,452	**88,589**
Asset Cond	36,599	23,870	46,730	29,872	40,972	**178,043**
NI	0	194	197	806	371	**1,567**
SC&P	34,461	33,081	33,114	11,522	10,244	**122,422**
	$111,243	$104,909	$116,487	$88,763	$93,023	**$514,425**

% of CAPEX Placed in Service

	FY2019	FY2020	FY2021	FY2022	FY2023	5 Yr Total
CR/PR	100%	104%	76%	74%	88%	**88%**
D/F	116%	106%	101%	105%	77%	**100%**
Asset Cond	111%	73%	112%	83%	93%	**95%**
NI	0%	133%	-343%	73%	24%	**46%**
SC&P	87%	133%	190%	75%	76%	**111%**
	100%	101%	116%	83%	86%	**97%**