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

Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan

21-Month Filing
April 2023 – December 2024

Book 1 of 2

December 22, 2022

Docket No. 22-53-EL

Submitted to**:**
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™

a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
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280 Melrose Street
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Rhode Island Energy™
a PPL company

January 4, 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. 22-53-EL – The Narragansett Electric Company
Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan
(21-Month Plan for Period April 2023 through December 2024)
<u>Alan T. LaBarre Testimony – Revised Page 2</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), please see enclosed a revised Bates 2 which is Page 2 of 10 of Alan T. LaBarre's Pre-Filed Direct Testimony (PDF Page 16 of 312 of the electronic filing). The revised page[1] corrects Line 15 by confirming Mr. LaBarre's testimony before the Public Utilities Commission in Docket No. 4382, Fiscal Year 2014 Electric Infrastructure, Safety, and Reliability Plan.

Please enclose the attached revised Bates 2 in the books that were provided to the Commission on December 27, 2022.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

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

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[1] Per communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by hard copies filed with the Clerk within 24 hours of the electronic filing.

Andrew S. Marcaccio, Counsel
PPL Services Corporation
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Providence, RI 02907
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December 23, 2022

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. 22-53-EL – The Narragansett Electric Company
Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan
(21-Month Plan for Period April 2023 through December 2024)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please see the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year ("FY") 2024 for review by the Public Utilities Commission ("PUC" or "Commission"). The Company respectfully requests that the PUC approve the enclosed Electric ISR Plan as filed.

On October 21, 2021, the Company submitted an earlier version of the enclosed Electric ISR Plan to the Division of Public Utilities and Carriers ("Division"). The Company consulted with the Division to try to reach an agreement on a proposed plan to be filed with the PUC; however, in this case, the Company and the Division were unable to reach an agreement. Accordingly, this Electric ISR Plan is being filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(d)(4), which provides that "[i]f the company and the division cannot agree on a plan, the company shall file a proposed plan with the commission and the commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long term, approve the plan within ninety (90) days."

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 support of the Electric ISR Plan, the Company has included pre-filed direct testimony of Alan T. LaBarre and joint pre-filed direct testimony of Nicole Begnal, Christopher Rooney, Kathy Castro, Ryan Constable, and Wanda Reder. As explained in the joint testimony, the Company is proposing spending of $327.8 million of capital investment (total for 21 months); $24.0 million of vegetation management O&M spending (total for 21 months); and $5.6 million of Other O&M spending (total for 21 months).

In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses the revenue requirement, rate design, and bill impacts. The Company's cumulative revenue requirement is $111.6 million (this includes $44.5 million for CY 2023 and $67.1 million for CY 2024). The Company has included joint pre-filed direct testimony of Stephanie A. Briggs, Jeffrey D. Oliveira, Andrew W. Elmore, and Natalie Hawk that describes the calculation of the Company's revenue requirement for CY 2023 and CY 2024. Please note that, in this case, the calculation also includes an adjustment for the tax hold harmless impact on ISR rate base.

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 increase of $1.32, or 0.8%. The Company has included pre-filed direct testimony of Peter R. Blazunas to describe the customer bill impacts of the proposed rate changes.

The Company is also enclosing copies of the Company's responses to the first, second, and third sets of discovery issued by the Division pertaining to the Plan. The Company's responses to fourth and fifth sets of discovery issued by the Division are due after the date of this filing and will be filed in the above-referenced docket. Please be advised that the Company's responses to DIV 1-20,[1] DIV 3-2, DIV 3-3, DIV 3-10, and DIV 3-11 contain confidential and privileged information. Pursuant to 810-RICR-00-00-1.3(H)(3) 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 two 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").

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 22-53-EL Service List
John Bell, Division (w/confidential information)
Greg Booth, Division (w/confidential information)
Christy Hetherington, Esq.
Al Contente, Division

[1] The attachments to DIV 1-20 (area studies) currently are being reviewed for Critical Energy Infrastructure Information ("CEII"). After review, the Company will make public the portions of the area studies that do not contain CEII. The Company anticipates this review will be completed in January 2023.

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

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

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

The Narragansett Electric Company d/b/a Rhode Island Energy (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 to DIV 1-20 which include Attachment DIV 1-20-1 (Blackstone Valley South Area Study); Attachment DIV 1-20-2 (Central RI West Area Study); Attachment DIV 1-20-3 (Newport Area Study); Attachment DIV 1-20-4 (Northwest RI Area Study); Attachment DIV 1-20-5 (South County West Area Study); and Attachment DIV 1-20-6 (Tiverton Area Study) (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the First 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 22, 2022. 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 and Critical Energy Infrastructure Information ("CEII"). 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.

Public disclosure of the information identified as CEII in the Confidential Attachments would negatively impact the Company's ability to effectively operate to provide safe and reliable service to its customers as CEII means a system or asset of the bulk-power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters. 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,

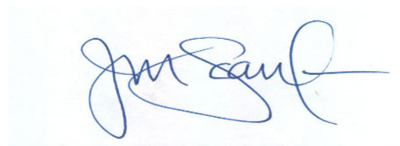
RHODE ISLAND ENERGY
By its attorney,

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

Dated: December 23, 2022

CERTIFICATE OF SERVICE

I hereby certify that on December 23, 2022, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 22-53-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 2024 ELECTRIC INFRASTRUCTURE, SAFETY AND RELIABILITY PLAN	)	DOCKET NO. 22-53-EL

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The records that are the subject of this Motion that require protective treatment from public disclosure are the Company's confidential Attachment DIV 3-2; confidential Attachment DIV 3-3; the confidential version of DIV 3-10; and the confidential version of DIV 3-11 (collectively, the "Confidential Attachments") which were submitted to the Division of Public Utilities and Carriers ("Division") in response to the Third 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 22, 2022. 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 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.

Public disclosure of the information would negatively impact the Company's ability to effectively operate to provide safe and reliable service to its customers. 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,

RHODE ISLAND ENERGY
By its attorney,

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

Dated: December 23, 2022

CERTIFICATE OF SERVICE

I hereby certify that on December 23, 2022, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 22-53-EL.

Joanne M. Scanlon

PRE-FILED DIRECT TESTIMONY

OF

ALAN T. LABARRE

Table of Contents

I. <u>Introduction and Qualifications</u>

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

A. My name is Alan T. LaBarre. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am Senior Director of Electric Operations for The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), an indirect wholly owned subsidiary of PPL Corporation ("PPL").

Q. What are your principal responsibilities in that position?

A. As Senior Director of Electric Operations for Rhode Island Energy, I have responsibility for overseeing the regulated electric distribution operations of Rhode Island Energy and for providing safe and reliable electric service to Rhode Island Energy customers.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Rhode Island. I am also a graduate of the Worcester Polytechnic Institute School of Industrial Management. I am a licensed professional engineer in the State of Rhode Island. Prior to starting at Rhode Island Energy in May 2022, I had just under 34 years of experience in electrical distribution infrastructure planning at National Grid USA

("National Grid"). During the first 12 years of my tenure with National Grid (1988 – 2000), I was responsible for the execution of area distribution system planning studies within the central and southeastern portions of National Grid's Massachusetts service territory. I held successive positions with increasing responsibility, advancing from Associate Engineer to Principal Engineer. Over the majority of the remaining years (2000 – 2021), I managed engineering groups of increasing size and scope of accountability responsible for executing distribution system planning activities. In April of 2021, I was assigned the role of Vice President of the New England Control Centers. On May 25, 2022, I started at my current position as Senior Director of Electric Operations for Rhode Island Energy.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC") or any other regulatory commissions?

A. Yes, while at National Grid, I testified before the PUC on behalf of the Company in Docket No. 4382, FY 2014 Electric ISR Plan. Also, while at National Grid, I testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Electric Company and Nantucket Electric Company, in Docket No. D.P.U. 18-150.

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to introduce Rhode Island Energy and to describe its vision and strategy for the future of electric operations in Rhode Island and the role of the Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability Plan ("FY 2024 Electric ISR Plan") in supporting that vision.

Q. How is your testimony organized?

A. My testimony is organized as follows: Section I is the Introduction. Section II discusses Rhode Island Energy's vision and how the FY 2024 Electric ISR Plan advances that vision. Section III provides an overview of the key investments within the FY 2024 Electric ISR Plan. Section IV provides a brief overview of the affordability of the FY 2024 Electric ISR Plan.

II. <u>Rhode Island Energy's Vision</u>

Q. Please describe Rhode Island Energy and its vision for Rhode Island.

A. Rhode Island Energy is the primary provider of electric and gas distribution services in Rhode Island. Rhode Island Energy's vision is aligned with PPL's mission to provide safe, affordable, reliable, and sustainable energy to its customers. PPL has a rich history of providing safe, reliable, and affordable service for PPL customers, demonstrated by its numerous awards for customer satisfaction and national recognition for its operational performance through advanced metering functionality ("AMF") implementation and grid modernization investments.[1] PPL also has a superior customer satisfaction record, having been awarded 58 total J.D. Power residential and business customer satisfaction awards for its utilities in Pennsylvania and Kentucky combined. PPL brings this history of accomplishment and wealth of experience to Rhode Island Energy and is integrating the operational practices that delivered those results into Rhode Island Energy's operations.

Q. What has Rhode Island Energy observed about the nature of Rhode Island's electric distribution system that drives its strategy for the future of energy in Rhode Island?

A. The electric distribution system has begun changing significantly because of: (i) the increasing adoption of additional renewable generation sources, including distributed energy resources ("DER"); (ii) beneficial electrification; (iii) electric vehicles ("EVs"); (iv) electric heat pumps; and (v) advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business, and that transformation is expected to accelerate. This transition has fundamentally changed the nature of electric distribution system operations by creating two-way power flow that is more dynamic, less predictable, and more complicated to manage to ensure safe and reliable electric distribution service. The Company already faces these challenges. The

[1] In 2019, PPL's Pennsylvania utility, PPL Electric Utilities Corporation ("PPL Electric"), won the Reliability One Best Improved Utility for Reliability based upon a measure of reliability performance data that was certified as part of the program. According to the Institute of Electrical and Electronics Engineers ("IEEE") and the Edison Electric Institute ("EEI") analyses, PPL Electric has performed in the first quartile for System Average Interruption Frequency Index ("SAIFI") every year for the last seven consecutive years.

increase in complexity will hasten exponentially with the continued proliferation of DER and as the energy generation industry and Rhode Island Energy act to meet the State's aggressive policy mandates to transition to renewable energy generation and net zero greenhouse gas emissions.

The 2021 Act on Climate[2] sets forth enforceable, statewide, and economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45 percent below 1990 levels by 2030 and 80 percent by 2040 and to achieve net-zero emissions by 2050. The 2022 amendments to the Renewable Energy Standard[3] further accelerate the shift to renewable energy resources by requiring 100 percent of electricity used in the State to be generated by renewable energy resources by 2033. These State policy mandates (collectively referred to as the "Climate Mandates") and the actions that energy generators and transmission and distribution utilities must perform to achieve them will cause Rhode Island Energy's operation of the electric distribution system to become much more dynamic and complex.

Q. What is Rhode Island Energy's strategy to address these challenges?

A. To ensure electric system safety and reliability and keep pace with this transformation, Rhode Island Energy must invest in the development of a safer and modernized

[2] R.I. Gen. Laws § 42-6.2-1 et seq.
[3] R.I. Gen. Laws § 39-26-1 et seq.

distribution system. Accordingly, Rhode Island Energy has evaluated the options available to adapt to these changed circumstances and developed a plan to make the necessary investments now that will provide the necessary, real-time situational awareness of system conditions together with the necessary control capabilities to mitigate these risks. The investments proposed in the FY 2024 Electric ISR Plan are necessary to address safety and reliability needs now and to ensure that the Company is able to manage the evolving electric distribution system in the future, efficiently and affordably. Accordingly, Rhode Island Energy's strategy is to be proactive and make the foundational investments that will enable the Company to deliver the safe and reliable – and resilient – electric distribution service that customers expect and deserve through improved automation, outage management, and sectionalization capabilities, among others.

Q. How does the Company's FY Electric 2024 ISR Plan align with Rhode Island Energy's vision?

A. The investments proposed in the FY 2024 Electric ISR Plan will put the Company on a trajectory to becoming a top-tier utility in terms of reliability and ensure that the electric distribution system will not be an impediment to the State in meeting its Climate Mandates.

Q. The Climate Mandates look out to the year 2050. Why are the FY 2024 Electric ISR Plan investments needed now?

A. The Company views increased DER penetration as inextricably linked to the achievement of Rhode Island's Climate Mandates. That DER penetration is already underway; Rhode Island has one of the highest DER saturation rates in the country. There is no evidence that the rate of adoption will slow. Accordingly, the prudent time to act is now. Delaying these investments will create a risk to integrating the DER while maintaining reliability.

III. <u>FY 2024 Electric ISR Plan</u>

Q. Why is Rhode Island Energy filing the FY 2024 Electric ISR Plan as a 21-month plan?

A. Rhode Island Energy has a legal obligation to provide safe and reliable service to its customers.[4] To ensure this standard of service is maintained, the Company files a proposed capital spending plan with the PUC each fiscal year.[5] To effectuate the transition from National Grid's fiscal year to PPL's fiscal year, Rhode Island Energy is filing a one-time 21-month plan for fiscal year 2024. The Company will return to a 12-

[4] R.I. Gen. Laws § 39-2-1(a) ("Every public utility is required to furnish safe, reasonable, and adequate services and facilities.").

[5] R.I. Gen. Laws § 39-1-27.7.1(d) ("… the company shall file a proposed plan with the commission and commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long term, approve the plan within ninety (90) days.).

month plan starting with the plan for fiscal year 2025, which also aligns with calendar year 2025.

Q. How is the Company's FY 2024 Electric ISR Plan beneficial to customers?

A. Customers will see improved reliability. Fewer outages and faster restoration times mean improved customer satisfaction. In addition, customers will feel confident that their electric distribution system is able to handle the current integration of DER and is ready for the aggressive measures that will need to be taken soon to achieve the State's Climate Mandates.

Q. Are there key performance metrics on which the Company is focusing to ensure that customers realize the reliability benefits?

A. Yes. The Company is focused on SAIFI performance, customer satisfaction surveys executed by J.D. Power, Customers Experiencing Multiple Interruptions ("CEMI") performance, and "blue sky" outages having greater than ten-hour restoration times.

Q. Are there any investments in the FY 2024 Electric ISR Plan that you would like to highlight?

A. Yes. Although the Company is excited about all the investments in the FY 2024 Electric ISR Plan, I would like to highlight a few key programs and initiatives.

(1) The installation of main line sectionalizing reclosers. This will reduce outages for customers and better equip the Company to remotely transfer load during an outage.

(2) The advancement of the infrastructure development recommendations stemming from the Company's long range area planning studies. These area planning studies were performed in consultation with the Division of Public Utilities and Carriers ("Division"), and the Company will be investing in the infrastructure needed to address areas of risk identified in the studies.

(3) The addition of foundational investments needed for grid modernization. These fundamental investments primarily consist of additional reclosers and reactive compensation and voltage management infrastructure.

(4) The execution of the Underground ("UG") Cable Replacement and Underground Residential Development ("URD") rehabilitation/replacement programs. This entails a strategy to replace underground cable that is in poor condition or has poor operating history.

The above projects and initiatives will be explained further in the Joint Pre-filed Direct Testimony of Company Witnesses Nicole Begnal, Christopher Rooney, Kathy Castro, Ryan Constable, and Wanda Reder.

IV. Affordability

Q. How is affordability, which is part of PPL's mission, taken into consideration?

A. Affordability is critical to any proposal, and the Company takes any rate increase seriously. In this case, the Company considered the urgency of the investments and the safety and reliability risks associated with delay against the projected bill impacts to customers. The $1.32 monthly increase[6] associated with the FY 2024 Electric ISR Plan is reasonable given those risks. In addition, customers will receive significant benefits over the short and long term related to investments that fall under the grid modernization framework. The forthcoming Grid Modernization Plan ("GMP") includes a benefit cost analysis that will show significant benefits, including a positive benefit cost analysis. If the Company does not make grid modernization investments now, it will be costlier for customers in future years as the Company reacts to issues that arise from the outdated electric distribution system infrastructure that is ill-equipped to manage the operational realities of the current and future electric energy ecosystem.

V. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

[6] For the typical residential customer using 500 kwh monthly, the bill increase for 21-months equates to $1.32 per month. Please see the Pre-Filed Direct Testimony of Peter R. Blazunas for additional details.

JOINT PRE-FILED DIRECT TESTIMONY

OF

NICOLE BEGNAL

CHRISTOPHER ROONEY

KATHY CASTRO

RYAN CONSTABLE

AND

WANDA REDER

Table of Contents

I. Introduction

Nicole Begnal

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

A. My name is Nicole Begnal. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy") as ISR Manager. In my position, I am responsible for the filing and reporting of electric infrastructure, safety, and reliability ("ISR") plans, as well as the electric distribution five-year investment plan.

Q. Please describe your educational background and professional experience.

A. In 2017, I graduated from the University of South Carolina with a Bachelor of Science degree in International Business, Finance and Risk Management. In June 2017, I joined National Grid USA Service Company, Inc. ("NGSC") as an Associate Project Manager in the Gas Complex Capital Delivery department, progressing to a Project Manager in October 2018. I managed the execution of liquefied natural gas ("LNG"), regulator station and leak-prone pipe projects in Rhode Island and Massachusetts. In 2021, I moved to Goulston & Storrs as a Project Management Organization ("PMO") Specialist, working on implementing project management practices and policies across the business. I completed my Master of Business

Administration degree in December 2021 from the College of William and Mary and Project Management Professional ("PMP") Certification in June 2022. I joined Rhode Island Energy in July of 2022 and assumed my role as ISR Manager.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC" or "Commission")?

A. No, I have not previously testified before the PUC.

<u>Christopher Rooney</u>

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

A. My name is Christopher Rooney. My business address is 642 George Washington Highway, Lincoln, Rhode Island 02865.

Q. Mr. Rooney, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as Manager of Distribution and Transmission Forestry. My position is responsible for the day-to-day operations of vegetation management as well as the long-term planning of the vegetation management program.

Q. Mr. Rooney, please describe your educational background and professional experience.

A. In 1998, I graduated from the University of Rhode Island with a Bachelor of Science degree in Horticulture. In 2003, I received a Master of Science in Urban and Community Forestry from the University of Massachusetts. I joined NGSC as a District Arborist covering the Capital district for distribution vegetation maintenance. In 2008, I became a Lead Forestry Supervisor covering distribution vegetation maintenance for Southern New England (Rhode Island and Massachusetts). I held that position until 2021 when I became the Manager of Distribution Forestry covering the same area. Upon the close of the Acquisition,[1] I assumed the Manager of Forestry for Transmission and Distribution for Rhode Island Energy.

Q. Have you previously testified before the Commission?

A. No, I have not previously testified before the PUC.

<u>Kathy Castro</u>

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

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

Q. Ms. Castro, by whom are you employed and in what position?

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

[1] On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation (“PPL”), acquired 100 percent of the outstanding shares of common stock of the Company from National Grid USA (“National Grid”)(the “Acquisition”).

Q. Ms. Castro, please describe your educational background and professional experience.

A. In 2003, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by NGSC as an Associate Distribution Design Engineer responsible for design of new facilities for business and capital improvement projects. In 2005, I earned a Graduate level Certificate of Power Systems Management and Engineering from Worcester Polytechnic Institute. In 2005, I joined the Distribution Planning and Engineering department as an Engineer, promoted to Senior Engineer in 2008. In this role, I was responsible for identifying asset, capacity, and reliability issues, justifying proposed solutions, and initiating selected projects for Operations and Substation engineering departments. I also reviewed and recommended solutions to serve customers requiring significant demand. In 2010, I joined a consultant company located in Rockland, Massachusetts as a Senior Engineer. In this role, I was responsible for completing distribution system impact analysis of distributed generation for utilities across New England and New York. Within one year, I was promoted to Manager of Engineering responsible for building a department that focused on Distribution Planning short- and long-term studies. In 2017, I was promoted to Director of Engineering overseeing Distribution Design and Planning functions. In March of 2018, I returned to NGSC and assumed the position as Manager of Distribution Planning and Asset Management, and on May 25, 2022, I became the Director of Asset Management & Engineering for Rhode Island Energy.

Q. Have you previously testified before the PUC?

A. Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2020 and FY 2021 electric ISR plans.

Ryan Constable

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

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

Q. Mr. Constable, by whom are you employed and in what position?

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

Q. Mr. Constable, please describe your educational background and professional experience.

A. I received a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, New York in 1993 and a Certificate of Industrial Management and Power Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts in 2000. I am a Registered Professional Engineer in Massachusetts, number

41632. I worked at NGSC from 1994 to 2000 and 2010 to May 24, 2022, after which time I joined Rhode Island Energy in my current position. I have held various positions of increasing responsibility in the area of Distribution Planning. From 1994 to 1998, I was a Project Engineer responsible for the design and maintenance of the electric infrastructure serving commercial and residential customers in southeastern Massachusetts. During the period 1998 to 2000, I was a Planning Engineer conducting long-range electric system studies. From 2010 to 2011, I worked as a Principal Engineer in the Utility of the Future department developing the Worcester Smart Energy Solution Pilot. In 2011, I became the Manager of Distribution Planning and Asset Management – New England, directing a ten-person team to conduct annual planning activities, perform long-range planning studies, and develop regulatory filings. In 2017, I became the Acting Director of the department. In the period 2000 to 2010, I worked for three independent transmission development companies, TransEnergie U.S., Cross Sound Cable Company, and Brookfield Renewable Power.

Q. Have you previously testified before the Commission?

A. Yes. I have previously testified before the PUC in support of the Company's FY 2023 electric ISR plan in Docket No. 5902, FY 2022 electric ISR plan in Docket No. 5098 and the Company's FY 2020 electric ISR reconciliation filing in Docket No. 4915.

<u>Wanda Reder</u>

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

A. My name is Wanda Reder. My business address is 34W676 Country Club Road, Wayne, Illinois 60184.

Q. Ms. Reder, by whom are you employed and in what position?

A. I am the President and CEO of Grid-X Partners, which is a certified Women's Business Enterprise consulting firm that provides insight and direction for electric and gas utility grid transformation. Grid-X Partners brings senior executive experience having a unique balance of technical, strategic, and practitioner capability. It assists utilities and their stakeholders in developing strategy, regulatory, and execution plans to address the complex challenges confronted by utilities in an evolving industry landscape. As CEO, my primary responsibilities include making all major corporate decisions, financial responsibility, managing the overall operations and resources of the company, and acting as the main point of communication between the consultants and our clients. I am testifying on behalf of Rhode Island Energy.

Q. Ms. Reder, please describe your educational background and professional experience.

A. I earned a Master of Business Administration with emphasis in New Ventures from the University of St. Thomas in St. Paul, Minnesota, and a Bachelor of Science in Engineering from South Dakota State University. I have more than 30 years of experience in the electric utility industry, with much of my career aimed at grid modernization thought leadership and transformation for electric utilities. Before founding Grid-X Partners, I served as Chief Strategy Officer and Vice President of Power Systems Services for S&C Electric Company ("S&C") from 2004 to 2018. There, I developed consulting, engineering, field services, and project management capability to address global service needs. Among many offerings, we designed, integrated, and commissioned grid-scale distribution automation projects as well as wind-power, solar, and storage projects for utilities and developers. Prior to S&C, I was a Vice President for Exelon Energy Delivery ("Exelon") responsible for several areas such as Asset Management, Engineering, and Planning. My group of more than 1,000 employees defined the transmission and distribution work portfolio in excess of $1 billion annually, developed and managed the budget, and prepared and scheduled the execution of work. Before Exelon, starting in 1987, I served in various capacities for Northern States Power (now Xcel) in executive and engineering roles, including leading transmission and distribution capacity planning and technology implementation for automated meter reading, distribution automation, distribution management, and demand-side management. I am an Institute of Electrical and Electronics Engineers ("IEEE") Fellow, served as President of the IEEE Power & Energy Society from 2008 to 2009, and was appointed to the U.S. Department of Energy Electricity Advisory Committee by the U.S. Secretary of Energy, serving a six-year term from 2011 to 2017, and again re-appointed in 2018 until the present, where I currently serve as its Chair. Also, I was invited to, and became a member of, the prestigious

National Academy of Engineers in 2016 for my leadership in electric power delivery and workforce development, where I currently serve on the Membership Policy and Finance Committees.

Q. Have you previously testified before the Commission?

A. I have not testified before the PUC; however, I recently submitted Joint Pre-Filed Direct Testimony in Docket No. 22-49-EL in connection with the Company's Advanced Metering Functionality ("AMF") Business Case. Prior to that, I presented regarding the AMF Business Case at the Workshop conducted by the PUC in Docket Nos. 4770 and 4780 on September 1, 2022, together with Mr. Walnock, and I presented about the Company's forthcoming Grid Modernization Plan ("GMP") at the Technical Session held on October 28, 2022, related to the Company's FY 2023 electric ISR plan in Docket No. 5209. In addition to my work in Rhode Island, I was an expert witness for PPL Electric's DER Management Petition, where the Company requested to proactively implement the 2018 revisions to IEEE Standard 1547, "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" ("IEEE Standard 1547" or "IEEE 1547-2018") and the related UL Standard 1741 to require new customers applying to interconnect new distributed energy resources ("DER") with PPL Electric's distribution system to use approved smart inverters that are compliant with IEEE 1547-2018 and to install devices that enabled PPL Electric to monitor and proactively manage individual customer DER. This included tariff revisions for the utility to monitor and manage customer inverters located behind the meter. My role was to present the background for the IEEE standard and showcase global trends and use cases that highlight the importance of the using the IEEE standard.

II. Purpose and Structure of Joint Testimony

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present the FY 2024 Electric Infrastructure, Safety, and Reliability Plan (the "FY 2024 Electric ISR Plan," "Electric ISR Plan," or "Plan"). As is described in the Plan, implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable cost. The proposed Electric ISR Plan is attached as Exhibit 1 to this testimony.

Q. How is the testimony structured?

A. In addition to the Introduction and Purpose and Structure of Joint Testimony (Sections I and II, respectively), our joint testimony includes the following sections:

- Description of how the Company developed the Electric ISR Plan and FY 2024 capital investment spending levels (Section III).
- Description of the Company's vegetation management program and FY 2024 spending levels (Section IV).
- Description of the Company's inspection and maintenance ("I&M") and other operation and maintenance ("Other O&M") programs and FY 2024 spending levels (Section V).

- Application of the Docket 4600 goals and Framework to certain new or incremental programs in the Electric ISR Plan for FY 2024 (Section VI); and

- Conclusion (Section VII).

Q. Please describe the approvals that the Company is seeking from the Commission in this proceeding.

A. To gain alignment with the Company's financial schedule,[2] Rhode Island Energy is submitting the Plan as a 21-month plan for approval. This Plan consists of the nine months from April 1, 2023, through December 31, 2023, which the Company defines as CY2023, and the 12 months from January 1, 2024, through December 31, 2024, which the Company defines as CY2024. The Company is seeking approval of the proposed FY 2024 21-month budget, 21-month rate, and proposed RIPUC No. 2264, Infrastructure, Safety, and Reliability Provision.

Q. Please summarize the categories of infrastructure, safety, and reliability spending covered by the Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2024, or the 21-month period from April 1, 2023, through December 31, 2024: capital spending on electric infrastructure projects; operation and maintenance ("O&M") expenses for vegetation management; O&M for I&M; O&M for grid modernization

[2] To transition the filing of ISR plans from National Grid's fiscal year (April 1 – March 31) to PPL's fiscal year (January 1 – December 31), the Company is proposing a one-time 21-month plan to cover the period from April 1, 2023, through December 31, 2024. Subsequent ISR plans would then align with PPL's fiscal year.

investments; and O&M for Volt/Var Optimization and Conservation Voltage Reduction ("VVO/CVR") Expansion.

Q. Please explain how the Electric ISR Plan is structured.

A. The Electric ISR Plan includes the spending plan for FY 2024 and a rate reconciliation mechanism that provides for recovery of related to capital investments and other spending undertaken pursuant to the pre-approved budget. The Electric ISR Plan itemizes the recommended work activities by general category and provides budgets for capital investment and O&M expenses for the vegetation management, I&M, VVO/CVR programs and grid modernization. After the end of the fiscal year, the Company trues up the ISR Plan's projected capital and O&M expense levels used to establish the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconciles the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year.

III. Capital Investment Plan

General Questions

Q. How does the Company prepare its capital investment plan?

A. In this filing, the Company has proposed a capital spending plan for FY 2024 totaling $327.8 million. The Company developed the proposed capital spending plan by considering: (i) work already underway or identified in area studies, which have been advanced by the annual capacity review process, (ii) reliability reviews, and (iii) the GMP, which was required per the Amended Settlement Agreement ("ASA") approved by the Commission in Docket No. 4770. The project work that is included in the Electric ISR Plan is specifically designed to meet system performance objectives and customer service requirements, which the Company must address as part of its public service obligation to provide safe and reliable service. In the Electric ISR Plan, the Company has provided a detailed explanation of the categories of investment, the factors motivating the nature and amount of investment, and the specific projects that will be undertaken in Rhode Island.

Q. Can you explain the annual capacity review process?

A. Yes. The annual capacity review is a current look at the Company's capacity capabilities, which identifies imminent thermal capacity constraints and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes a review of forecasted peak load on each sub-transmission line, substation transformer, and distribution feeder in the entire service territory with a comparison to equipment ratings and consideration of system operational flexibility to respond to various contingency scenarios.

Q. Can you explain how the results from the annual capacity review are used?

A. Yes. When capacity reviews highlight an area that has capacity constraints of a level where a detailed and comprehensive review is warranted, that area is identified as needing an area planning study. Area study priority is determined by assessing the number and severity of electrical issues, with secondary considerations such as the area statistics (complexity) and the date of previous study efforts. The priority is reviewed and adjusted prior to the start of any new study, but, at a minimum, at least once a year. Other prompts for an area planning study include the identification of asset condition issues, large new customer load request, or acute reliability issues. Chart 6 in Section 2 of the Plan provides the status of annual capacity reviews and the prioritization and status of area planning studies. As shown in Chart 6, the Company has completed 100 percent of the annual capacity reviews in the eleven study areas. The area study planning process is further described in Section 2 of the Plan. Concluding with the completion of the Newport Area Study in December 2021, the Company has completed all Rhode Island area studies and reviewed results with the Division of Public Utilities and Carriers ("Division").

Q. Please summarize the significant changes related to the approach in utilization of the area study results from the change in the Company's ownership from National Grid to PPL.

A. The Company has recognized and accepted the results of the long-range area studies completed prior to the change of ownership from National Grid to PPL. The inputs and results of the area studies have not changed since the Acquisition. The Company views planning criteria as a "bright line" and will address violations of criteria by advancing study infrastructure development recommendations as expeditiously as possible. This focus along with other factors, such as resource availability, has informed the priority and sequence of projects.

Q. Please summarize the significant changes related to reliability targets from the change of Company ownership from National Grid to PPL.

A. Rhode Island Energy acknowledges that its reliability performance meets regulatory requirements; however, there is an upward trend in both the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") as highlighted by Section 4, Attachment 4, Charts 1 and 2. Based on IEEE SAIFI benchmarking results, the Company consistently ranked in the second quartile, and, although 2021 shows first quartile performance, the Company is at the bottom of that quartile. The Company considers its current average performance as second quartile. Based on latest J.D. Power results, overall Customer Satisfaction, which has a direct correlation to reliability, has plunged to fourth quartile. All measures indicate a declining reliability performance of the system and underscore the need for course correction, which the Company sees as a priority. The Company has established an internal goal of achieving top first quartile SAIFI performance when compared to peer utilities, which is better performance than required under the PUC's performance penalty threshold of 1.05.

Q. Is it beneficial to customers for the Company to make investments to achieve its internal goal of top first quartile SAIFI performance?

A. Yes. These comparative system reliability metrics are a key indicator of utility performance. An internal goal to achieve top tier performance helps drive a culture of continuous improvement and can ensure, proactively, that Rhode Island Energy is meeting and exceeding reliability expectations – rather than reactively responding if or when reliability metrics start to decline.

Q. What process did the Company undertake to prepare its FY 2024 Electric ISR Plan for review by the Commission?

A. The Company submitted its pre-filing documentation to the Division and began discussions in September regarding the FY 2024 Electric ISR Plan. The Company submitted the first draft to the Division on October 21, 2022, for review pursuant to R.I. Gen. Laws § 39-1-27.7.1(d). The Company and Division met on multiple occasions to discuss the proposed investments, specifically focused on grid modernization and reliability. After various meetings, there was not a consensus on the Plan prior to filing with the Commission. The Division proposed decreasing the budget, mentioning concerns around the overall increase in capital spend as well as affordability.

Q. Why did the Company reject the Division's proposed decreased budget?

A. The Company proposed investments that it determined were necessary to maintain the safety and reliability of the electric distribution system. The Company carefully considered the Division's proposed adjustments and determined that they did not include information that convinced the Company that these investments are not necessary. Rather, the Division's proposal focused on decreasing the proposed level of investment. The Company takes seriously the need to maintain affordability for all customers. Taking that into account and balancing it against the safety and reliability needs, the Company concluded that the relatively modest $1.32[3] monthly increase associated with the proposed FY 2024 Electric ISR Plan investments is reasonable.

Q. Please describe the categories of work activities that are included in the Electric ISR Plan to address service reliability.

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments necessary to improve the performance of discreet aspects of the system, thereby, resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) respond to customer requests or city, state, and town requirements; (2) repair failed or

[3] For the typical residential customer using 500 kWh monthly, the bill increase for 21-months equates to $1.32 per month. Please see the Pre-Filed Direct Testimony of Peter R. Blazunas for additional details.

damaged equipment; (3) enable DER integration and achieve State Climate Mandates;[4] (4) address load growth/migration; (5) maintain reliable service; and (6) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island.

Q. Does the Plan impact the State's ability to achieve its Climate Mandates?

A. Yes. The Plan positively impacts the State's ability to meet its mandates. As explained in greater detail both in the Plan and in the soon-to-be-filed GMP, the investments proposed in this Plan, particularly the grid modernization investments, are critical to enabling the Company to operate the electric distribution grid safely and reliably while also integrating the level of DER proliferation and increased electric demand necessary to meet the emissions reductions and increased renewable energy generation called for by the Climate Mandates.

Q. Please review the FY 2024 capital investment levels.

A. The investment levels proposed for recovery through the FY 2024 Electric ISR Plan fall within six key work categories: Non-discretionary work includes (1) Customer Request/Public Requirement; (2) Damage/Failure; and (3) Grid Modernization.

[4] The State's "Climate Mandates" include the 2021 Act on Climate, codified as R.I. Gen. Laws § 42-6.2-1 et seq., and the 2022 amendments to the Renewable Energy Standard ("RES"), codified as R.I. Gen. Laws § 39-26-1 et seq.

Discretionary work includes (4) Asset Condition; (5) Non-Infrastructure; and (6) System Capacity and Performance. The table below summarizes the proposed spending level for each of these key driver categories.

Proposed FY 2024 Capital Investment by Key Driver Category
($000)

Spending Rationale	Proposed Budget	%
Customer Request/Public Requirement	$49,040	15%
Damage/Failure	$27,529	8%
Grid Modernization	$81,860	25%
Asset Condition	$114,993	35%
Non-Infrastructure	$2,664	1%
System Capacity and Performance	$51,684	16%
Total	**$327,770**	**100%**

As shown in the table above, a significant portion of the investment for capital projects are necessary to meet customer requests or city, state, and town requirements. (*i.e.*, $49.0 million or 15 percent). These investments respond to new customer requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation. Overall, the scope and timing of this work is defined by others external to the Company. The need to repair failed and damaged equipment totals approximately $27.5 million, or eight percent of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes. The costs associated with the Nasonville substation rebuild are also included in the FY 2024 Damage/Failure category.

Grid modernization is a new spending category in the FY 2024 ISR Plan. These investments are needed now because of deteriorating reliability trends increased operational risk present with the high DER adoption rates reinforced by the State Climate Mandates, growing interconnection queues, and supply chain delays and material availability. Together, these items account for approximately $81.9 million, or 25 percent of proposed capital investment and are considered mandatory or "non-discretionary" in terms of scope and timing because they are driven by our statutory requirements to provide safe and reliable service. Because the investments associated with these categories of work are non-discretionary, both in terms of timing and scope and are driven by forces outside the Company's control, these categories of spending are subject to necessary and unavoidable deviations.

The asset condition, system capacity and non-infrastructure projects that the Company will pursue in FY 2024 have been chosen to maintain the overall reliability of the system and collectively total approximately $169.3 million, or 52 percent of the Company's proposed FY 2024 capital investment. Some of the Company's electric infrastructure assets are almost 100 years old and are ready for replacement. Projects necessary due to the condition of infrastructure assets account for approximately $115.0 million, or 35 percent of the Company's proposed FY 2024 capital investment. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company plans these investments to minimize potential reliability issues. One example of a project in the FY 2024 Plan is the replacement of the Admiral Street Substation, which was constructed in 1930.

System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers. Generally, projects in this category address load conditions on substation transformers and distribution feeders recommended by the Company's annual capacity review and Area Planning Studies. System Capacity and Performance projects account for approximately $51.7 million, or 16 percent, of the proposed capital investment in FY 2024. Examples of large projects in this category include the New Lafayette Substation, a new 115/12.47 kV substation, which arose from the South County East Area Study, East Providence Substation, a new 115/12.47 kV substation, and expansion of the Warren Substation. The East Providence and Warren Substation projects arose from the East Bay Area Study.

Q. Throughout the Plan term, will the Company provide periodic updates regarding the various categories of capital work approved?

A. Yes. The Company will continue to file quarterly reports on the progress of its Electric ISR Plan programs. Additionally, the Company will provide a report on the fiscal year activity when it submits the reconciliation and rate adjustment filings to the Commission at the end of the Plan, ending December 31, 2024. In executing the approved Electric ISR Plan, circumstances encountered may require reasonable deviations from the original Plan. In such cases, the Company will include an explanation of any significant deviations – both in its quarterly reports and in its fiscal year-end report. The Company will continue to meet quarterly with the Division approximately one month after each quarterly report is filed with the Commission and discuss progress and updates to the Plan and address questions the Division has.

Large Projects and Programs

Q. Please describe the FY 2024 spending levels for the Company's Asset Condition projects from area studies that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The Company is introducing $23.0 million of Asset Condition spend for new projects from completed area studies to address safety concerns from the poor condition of aged assets. This includes work identified in nine different area studies.

Q. Please describe the FY 2024 spending levels for the Company's System Capacity & Performance projects from area studies that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The Company is introducing $16.0 million of new projects under the System Capacity & Performance spending rationale. This includes work identified in eight different area studies. This work will allow for more flexibility in the system for purposes of meeting various contingencies such as load growth and migration.

Q. Please describe the FY 2024 spending levels for the Company's Mainline Recloser Program that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The FY 2024 Electric ISR Plan has spending of $9.504 million related to the Mainline Recloser Enhancement Program. New proximity and focus have allowed Asset Managers to recognize an immediate need to change system topology and address deteriorating reliability. From October 30, 2021, through October 30, 2022, Rhode Island Energy experienced 112 sustained circuit breaker interruptions, which equates to one circuit breaker outage approximately every three days during fair weather days. A review of circuit reclosers identified approximately 100 4kV and 15 kV circuits having greater than one mile of overhead line exposure and more than 100 customers that have zero reclosers. In addition, there are approximately 70 15kV circuits having greater than five miles of overhead line exposure and more than 1,000 customers that have only one recloser. The absence of reclosers on these circuits increases the amount of customer outages because of the lack of sectionalization and reduces the ability to remotely transfer load during an outage. The Company proposes capital spending in the 21-month plan to install approximately 100 mainline reclosers. All reclosers will use the latest control technology aligned with the pending GMP and location selection will be aligned with ultimate GMP implementation.

Q. Please describe the FY 2024 spending levels for the Customers Experiencing Multiple Interruptions ("CEMI") Program that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. There is $2.5 million of spending related to the CEMI Program in FY 2024. This program is being introduced to identify and fix reliability issues for customers experiencing significantly poorer service than system or circuit averages. System and Circuit Average Interruption Frequency Indices measure the experience of the average customer; however, using them exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This leads to uneven reliability performance across the distribution circuits and unhappy customers. Currently, approximately 12 percent (60,000) of Rhode Island Energy customers experience four or more interruptions in a rolling twelve-month period, putting Rhode Island Energy in the third quartile of performance. The CEMI 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.

Q. Please describe the FY 2024 spending levels related to Underground Residential Development ("URD") and Underground ("UG") Cable Replacement Programs that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The FY 2024 Electric ISR Plan has spending of $23.1 million related to URD and underground cable projects. Of the $23.1 million, there is $10.4 million of underground cable work. This program implements the strategy to replace primary underground cable that is in poor condition or has poor operating history. This program targets known problematic cable types such as paper and lead insulated cables and certain cross-linked polyethylene insulated cables. For URD work, there is approximately $12.7 million of spend in the Plan. This program supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although interruptions on #2 and 1/0 cables do not significantly influence Company-level service quality metrics, they can have significant localized impacts on affected neighborhoods.

Grid Modernization

Q. Please describe the FY 2024 spending levels related to grid modernization investments that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The FY 2024 Electric ISR Plan has spending of $81.9 million related to grid modernization investments. The Company's existing electric distribution system provides little distribution operator visibility and limited automated control. Accelerated grid transformation is needed to manage system complexity that is caused by increased DER penetration and electrification already occurring and by anticipated growth. Grid modernization investments that are designated as such in the Plan are needed now for safe and reliable operations. Advanced Distribution Monitoring System ("ADMS"), advanced reclosers, DER Monitor/Manage, electromechanical relay upgrades, fiber, IT infrastructure, mobile dispatch and smart capacitors and regulators are the different integrated components that make up the grid modernization "Foundational Investments"[5] within the Plan.

Q. How are the grid modernization components listed above (ADMS, advanced reclosers, DER Monitor Manage, electromechanical relay upgrades, and fiber investments, IT infrastructure investments, mobile dispatch, the smart capacitors & regulators) beneficial to customers?

[5] Please note "Foundational Investments" will be defined in the forthcoming Grid Modernization Plan.

A. The grid modernization components work together and are integrated to achieve optimum benefits for customers. The results of a Benefit/Cost Analysis ("BCA"), consistent with Docket No. 4600, will be finalized through the forthcoming GMP. The BCA will demonstrate the benefits and costs of implementing GMP Foundational Investments across the Rhode Island Energy service territory.

As will be confirmed through the BCA, the reliability and safety, customer, operational, clean energy, and financial benefits justify immediate deployment of the Foundational Investments, which is dependent upon approval of the proposed FY 2024 Electric ISR Plan grid modernization investments.

The Foundational Investments are near-term solutions in the GMP roadmap, which are generally installed by 2028 and are required to operate now and, in the future, regardless of DER adoption rates. Without these Foundational Investments it is likely that:

- Safety and reliability cannot be maintained due to the lack of visibility, situational awareness, and automated control of the distribution network given the two-way power flow conditions that are now being imposed on the system with higher levels of DER penetration.

- The Climate Mandates cannot be achieved even with massive transmission and distribution infrastructure buildout due to the amount of DER curtailment that would be required and the inability to monitor and control DER – Solar PV and storage batteries.

Q. Please provide an update on when the Company will be filing its GMP.

A. The GMP is expected to be filed electronically with the PUC on December 30, 2022, followed with the paper copies delivered to the PUC by January 3, 2023.

Q. How will the GMP interact with the FY 2024 Electric ISR Plan?

A. The GMP will present a holistic suite of grid modernization investments and will serve as an informational guidance document that supports the Foundational Investments proposed in the FY2024 Electric ISR. The GMP will also support additional grid modernization investments to be proposed in future electric ISR plans.

The first 21 months of the investments described in the GMP are included in the FY 2024 Electric ISR Plan. Due to the urgent need for the Foundational Investments that are defined in the GMP, the Company has included them as non-discretionary investments in the FY2024 Electric ISR Plan.[6]

As the proceedings advance in this docket, the Company intends to reference and rely upon the descriptions, explanations, justifications, and, particularly, the BCA contained in this GMP. Accordingly, the GMP will serve as a supplement and a necessary complement to the FY 2024 Electric ISR Plan and includes critical information including a comprehensive benefit-cost analysis aligned with the Docket 4600 principles.

Moreover, the GMP demonstrates the Company's longer-term approach to grid modernization, explaining how the Foundational Investments not only provide needed functionality for the Company to continue to deliver and enhance safe and reliable service for customers today, but also how those investments enable even greater functionalities to deliver even greater benefits for Rhode Island customers when integrated with additional investments in the future.

[6] Many factors support the conclusion that the Foundational Investments are urgent, including: (i) deteriorating reliability trends; (ii) a lengthening distributed generation interconnection queue; (iii) increased operational risk because of hidden load during switching; (iv) voltage variability; (v) lack of situational awareness as evidenced during the August 2022 Nasonville event; (vi) high DER adoption rates reinforced by the Climate Mandates and various incentives; and (vii) a compromised supply chain, resulting in imminent delays for material availability.

Q. What are the potential impacts of the proposed grid modernization investments in relation to the carbon dioxide emission reductions requirements as set forth in the Climate Mandates?

A. Rhode Island's Climate Mandates[7] provide the basis for expectations that the proliferation of DERs and electrification of vehicles and the heating sector will be accelerating. The grid modernization investments in the FY 2024 Electric ISR Plan are necessary for Rhode Island to be able to achieve the Climate Mandates. Enabling DER adoption, in particular renewable distributed generation ("DG"), electric vehicles ("EV"), and electric heat pump ("EHP") adoption, is key because it will enable customers to reduce their overall carbon footprint, including reducing the transportation-related emissions that make up 40 percent of the State's carbon dioxide (CO2) emissions.[8] Without these investments, the Company will need to continue to make piecemeal investments in distribution system infrastructure rather than being able to optimize those investments to benefit all customers and meet specific identified needs. Consequently, DG adoption rates likely will slow, EV charging infrastructure likely will be more costly,

[7] The 2021 Act on Climate set forth enforceable, statewide, economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% by 2040, and to achieve net-zero emissions by 2050. The 2022 amendments to the Renewable Energy Standard further accelerate the shift to renewable energy resources by requiring 100% of electricity used in the State be generated by renewable energy resources by 2033. See R.I. Gen. Laws § 42-6.2-1 et seq. (2021 Act on Climate) and R.I. Gen. Laws § 39-26-1 et seq. (Renewable Energy Standard).

[8] See U.S. Energy Information Administration, 2017 Data, Energy-Related CO2 Emission Data Tables, at Table 4 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/

and customer participation in DER and energy efficiency ("EE") programs likely will be less robust, likely putting the Climate Mandates out of reach.

Q. What is ADMS?

A. ADMS[9] is the central linkage between AMF and grid modernization by providing functionality for Operational Systems and Applications anchoring capability achieved by the GMP roadmap. As will be more fully described in the GMP, the ADMS integrated with Distribution SCADA ("DSCADA"), the Outage Management System ("OMS"), and the Distribution Management System ("DMS") advanced applications will enable a common network platform for operations that will enable Distribution Control Center operators to make more optimal system configuration decisions considering the actual constraints of the grid. This capability is an operational necessity to operate the system safely and reliably with mounting complexities from DER interconnections.

Q. What are advanced reclosers?

A. Advanced Reclosers are intelligent switches used in the mainline of the feeder that can interrupt power flow in response to a short circuit and then automatically allow power

[9] As part of Rhode Island Energy's transition to PPL's system, ADMS Basic, the ADMS platform PPL currently has in place in Pennsylvania, will be provided to Rhode Island Energy for its distribution management system operations. As a condition of the Acquisition approval, PPL committed to not seeking recovery of transition costs from Rhode Island customers. Part of the transition includes utilizing ADMS Basic by Rhode Island Energy. Advanced ADMS builds upon ADMS Basic proposing phased-in enhancements to increase functionalities and benefits that are described in the GMP. ADMS integrates Distribution Control Center hardware and software that will provide greater visibility, situation awareness, control, and optimization of the electric distribution grid, as well as efficiencies by automating control center processes.

flow to resume a short time later. Advanced Reclosers provide several benefits including system visibility, sensing and operational efficiencies, but their primary benefit is improving system reliability. Specifically, they are intended to create SAIFI benefits to reverse the Company's current declining trend in reliability performance as discussed in the GMP. When used in combination with ADMS, advanced reclosers enable automatic fault isolation and service restoration ("FLISR"), ultimately resulting in improved reliability and service to Rhode Island Energy customers.

Q. What is DER /Monitor/Manage?

A. DER Monitor/Manage enables the visibility of DERs and the ability to manage them. This management ranges from ramping operations to full curtailment of an individual DER output if needed, for distribution safety or reliability purposes. Where DER are both visible and controllable, their operation can be managed to minimize negative impacts to the electric distribution system while optimizing the benefits. Visibility and controllability are prerequisites for fully integrating DER, and that capability is not available today at Rhode Island Energy.

DER Monitor/Manage includes a suite of devices, software and communications that is needed to fully integrate smart inverters with utility operations at all levels. As DER penetration continues to grow, operation and planning challenges such as voltage swings, masked or hidden load, limited hosting capacity, planning uncertainties, and protection coordination become increasingly significant challenges. In response to these challenges, the IEEE revised Standard 1547 in 2018 ("IEEE 1547-2018"), which set forth requirements for smart inverters that can help support the distribution system. When these smart inverters are coupled with DER management devices, communications and ADMS-DERMS application, electric utilities can monitor and manage DER that interconnected with their distribution systems to optimize their value for the distribution system and customers.[10]

Q. What do the electromechanical relay upgrades consist of?

A. Electromechanical relay investments include upgrading solid-state, first-generation, electromechanical relays to digital relays over five years. The Company's current relays provide little data or flexibility. Upgraded relays will adapt to system changes and conditions with flexible settings and custom logic. As explained in the GMP, the latest generation of technology featuring over-the-air firmware upgrades is critical for future-proofing, providing dynamic protection capability in the future and maintaining a secure system to keep devices up to date. Additionally, the fault location information provided

[10] The Company understands that certain additional regulatory approvals are likely necessary, and the Company intends to seek any additional regulatory approvals, including any necessary tariff changes, in separate, forthcoming filings.

by digital relays minimizes outage duration because the time spent searching for issues to address them is reduced.

Q. What are the fiber investments?

A. Fiber investments are proposed to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul data from other installed grid modernization investments and AMF smart meters. This technology is needed to accommodate the vast quantity of operational data required for GMP and AMF. The network will provide security, speed, and bandwidth to achieve the required functionality and to achieve cost-effective benefits.

Q. What IT infrastructure investments are being proposed?

A. The proposed IT infrastructure investments include building foundational data management capabilities by enabling enhanced data governance across key datasets including an enterprise integration platform that will provide all the necessary integrations between the various grid modernization applications such as ADMS, VVO/CVR, data management and storage, and GIS integration. This plan also includes a cyber services component that is built from the principles and policies established in the PPL Data Governance Plan, filed as Attachment H in the AMF Filing and again in the GMP.

Q. What is mobile dispatch?

A. This project proposes investment in a mobile dispatch system and devices. ADMS-based mobile dispatch allows efficient utilization of field crews based on location, capabilities, and equipment, thereby improving restoration times, accuracy of restoration efforts, and worker safety. This can result in more efficient utilization of field crews and shorten outage response time. Mobile dispatch is being proposed now to improve customer service by reducing outage times and improving operational efficiency.

Q. What are the smart capacitors and regulators?

A. This project would upgrade the Company's existing capacitors and regulators without advanced controls to allow for dynamic adjustment of system voltages to accommodate the variable output of DER and better manage voltage along individual feeders. Advanced capacitors and regulators become part of an integrated system, which will be described in greater detail in the GMP. When they are operated with the ADMS – VVO application using inputs from the AMF granular voltage data, the distribution system can be monitored and managed such that voltage is compliant with regulations and optimized to result in energy efficiency and customer savings.

IV. Vegetation Management Program

Q. Please describe the FY 2024 spending levels for the Company's Vegetation Management Program that the Company has identified as appropriate to maintain safe and reliable distribution service to customers.

A. For FY 2024, the Company proposes to spend approximately $24.0 million for the Vegetation Management Program. The Company currently is making gradual changes to the program, with the goal of maximizing reliability benefits by using data analytics. One example of this includes introducing On-Cycle Outage Risk Reduction work, which will aim to address all concerns on one circuit at once. This eliminates risk as well as costs associated with going back to a particular circuit. The Company reviewed the coming changes in a meeting with the Division on November 10, 2022.

Q. Please discuss the changes associated with the Cycle Pruning portion of the Vegetation Management Program.

A. The Company is in the process of modifying the traditional four-year cycle pruning program. The Company will be using data analytics to generate its annual feeder list, taking into consideration the different areas of the state and growing degree days. Depending on these variables, this could lead to cycle trimming schedules that could be shorter or longer than the traditional four-year cycle in different areas of the State. The Company is also looking to enhance its pruning specifications to expand vegetation clearance distances.

V. Inspection and Maintenance Plan and Other O&M

Q. Please describe the FY 2024 spending levels for the Company's I&M and Other O&M Program that have been identified as appropriate to maintain safe and reliable distribution service to customers.

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The I&M Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground system components. The approximately $1.6 million budgeted for the I&M Program include O&M repairs associated with the capital program, inspections, voltage testing, and completion of 20 percent of the Contact Voltage Program ordered in Docket No. 4237. The other O&M expenses also include $25,000 for the on-going long-range system capacity load study, $0.7 million for O&M expenses for the Volt/Var expansion program, and $3.2 million related to grid modernization. The Company proposes a total O&M expense budget of approximately $29.6 million.

VI. Docket 4600 Benefit-Cost Framework Analysis

Q. Was Docket 4600 Benefit-Cost Framework Analysis completed for proposed investments in the FY 2024 ISR Plan?

A. Yes, the Company performed a Docket 4600 Benefit-Cost Analysis on four projects. The projects included have proposed capital spending greater than $2 million during the Plan term. The results of the analysis can be found in Attachment 5 of the Plan.

Q. Please discuss the BCA completed for the grid modernization investments.

A. Grid modernization investments have a separate BCA that was completed utilizing the Docket 4600 framework. The Company will include this analysis within the GMP filing, and the Company incorporates that forthcoming filing in support of the grid modernization investments proposed in the FY 2024 Electric ISR Plan.

VII. Conclusion

Q. In your opinion does the Electric ISR Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Electric ISR Plan is designed to establish the capital investment, vegetation management, and I&M activities in Rhode Island that are necessary to meet the needs of Rhode Island customers and maintain the overall safety and reliability of the Company's electric distribution system. The proposed Plan accomplishes these objectives. Each and every proposed investment, including the O&M activities, is reasonably needed to maintain safe and reliable distribution service over the short and long term. Therefore, the Commission's approval of the proposed Electric ISR Plan is essential for the Company to continue maintaining a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

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

Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan

21-Month Filing
April 2023 – December 2024

Book 1 of 2

December 22, 2022

Docket No. 22-53-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™

a PPL company

Table of Contents

Section 1
Executive Summary

Proposed FY 2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

Section 1: Executive Summary

The Narragansett Electric Company d/b/a Rhode Island Energy ("Company") has developed the proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan" or "21-Month Plan") in compliance with Rhode Island's Revenue Decoupling statute, which provides for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[1] To gain alignment with the Company's financial schedule,[2] Rhode Island Energy is submitting the Plan as a 21-month plan for approval. This Plan consists of the nine months from April 1, 2023 through December 31, 2023 and the 12 months from January 1, 2024 through December 31, 2024. For purposes of avoiding confusion, the Company has labeled the time periods referenced within the Plan as follows:

- National Grid or NG FY 2023 means April 1, 2022 through March 31, 2023
- CY 2023 means the 9-month period of April 1, 2023 through December 31, 2023
- CY 2024 means January 1, 2024 through December 31, 2024
- 21-Month Plan means April 1, 2023 through December 31, 2024

[1] R.I. Gen. Laws § 39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.
[2] On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL"), acquired 100% of the outstanding shares of common stock of the Company from National Grid USA ("National Grid"). To transition the filing of ISR plans from National Grid's fiscal year (April 1 – March 31) to PPL's fiscal year (January 1 – December 31), the Company is proposing a one-time 21-month plan that will run from April 1, 2023 through December 31, 2024. Subsequent ISR plans would then align with PPL's fiscal year which runs from January 1 through December 31.

Through the Plan, the Company proposes both capital and operation and maintenance ("O&M") spending to provide safe and reliable electric service.

The 21-Month Electric ISR Plan includes an overview of the system planning process that leads to the Company's long-range plan; the development of the Work Plan and the estimating process; the proposed 21-Month Capital and O&M spending plan; a description and calculation of the revenue requirement; a description of the proposed rates; and customer bill impacts. The Company will continue to file quarterly reports with the Division and the Rhode Island Public Utilities Commission ("Commission") concerning the progress of its Electric ISR Plan programs. In addition, the Company will file the report on the 21-Month ISR Plan activities when it submits its reconciliation and rate adjustment filing. In implementing the Plan, the circumstances encountered during the period may require reasonable deviations from the original Plan. In such cases, the Company will include explanations of significant deviations in its quarterly and annual reports.

Through the Plan, the Company will maintain and upgrade its electric distribution system by proactively replacing aging equipment, upgrading equipment to address load growth or migration, respond to emergency and storm events, and address infrastructure requirements that arise out of state, municipal, and third-party construction projects. In addition, the Company will continue to expand investments which address poor performing areas of the system to provide improved reliability defined by industry wide accepted performance metrics in addition to regulatory targets. The 21-Month Electric ISR Plan proposes a budget as follows:

Electric ISR Plan Budget	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23- 12/31/23	CY 2024 12 Mos. 1/1/24- 12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Capital Spending	$104,750	$147,365	$180,405	$327,770
Vegetation Management O&M	$11,875	$10,595	$13,436	$24,031
Other Programs O&M	$1,264	$2,608	$3,006	$5,614

Section 2
Electric Capital Plan

Proposed FY 2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

Section 2: Electric Capital Plan

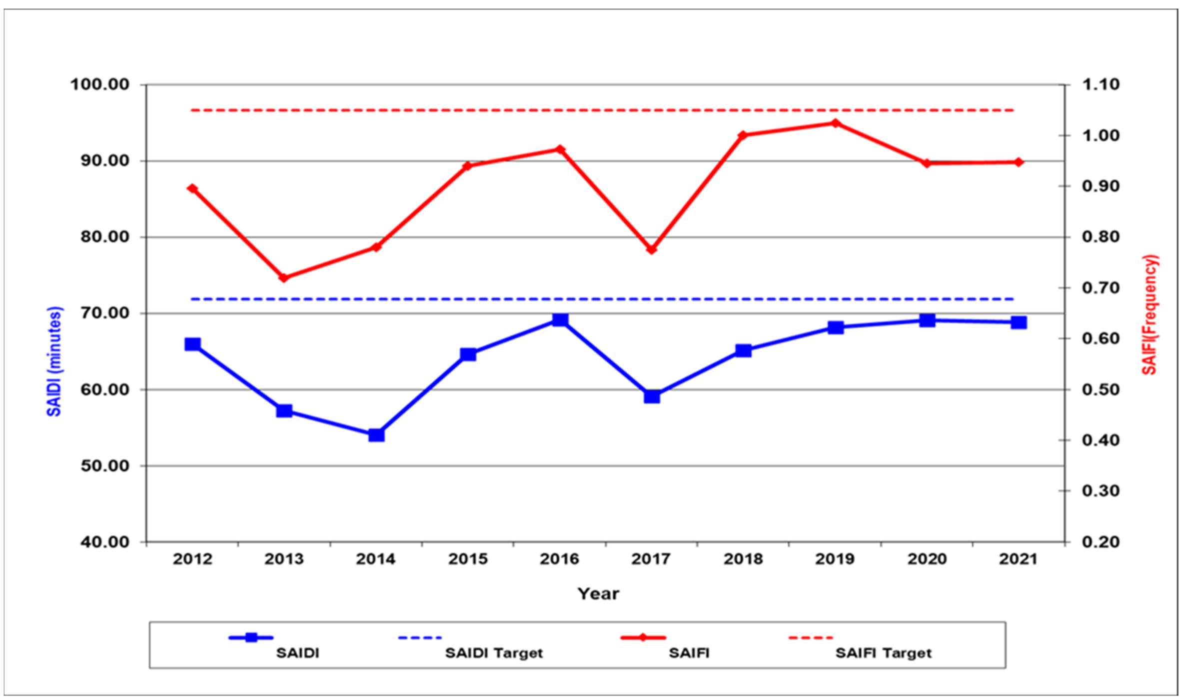
The Company developed the 21-Month Electric ISR Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs. As of March 2022, the Company delivers electricity to 501,236 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,134 miles of overhead and 1,145 miles of underground distribution and sub-transmission circuit that includes 408 distribution feeders and 56 sub-transmission lines. The Company relies on 59 distribution substations that house 111 power transformers and 919 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 283,585 distribution poles, 4,659 manholes, and 67,682 overhead (pole mounted) and underground (pad-mounted or in vault) transformers.

The Plan includes spending needed to (1) respond to customer requests and city, state, and town requirements; (2) repair failed and damaged equipment; (3) address load growth and migration; (4) maintain reliable service; (5) sustain asset viability through targeted investments driven primarily by asset condition; and (6) enable Distributed Energy Resource ("DER") integration and meeting State clean energy goals.

Since the inception of the ISR in FY 2012, the Company has consistently met its system reliability goals. As shown in Chart 1 below, the Company met both its calendar year ("CY") System Average Interruption Frequency Index ("SAIFI") and System Average Interruption

Duration Index ("SAIDI") performance metrics in CY 2021, with SAIFI of 0.949 against a target of 1.05, and SAIDI of 68.8 minutes against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days.[3] See Attachment 4 for further detail related to system performance reliability data.

Chart 1
RI Reliability Performance
CY 2012 – CY 2021
Regulatory Criteria (Excluding Major Event Days)



3 A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (6.67 minutes for CY 2021). For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

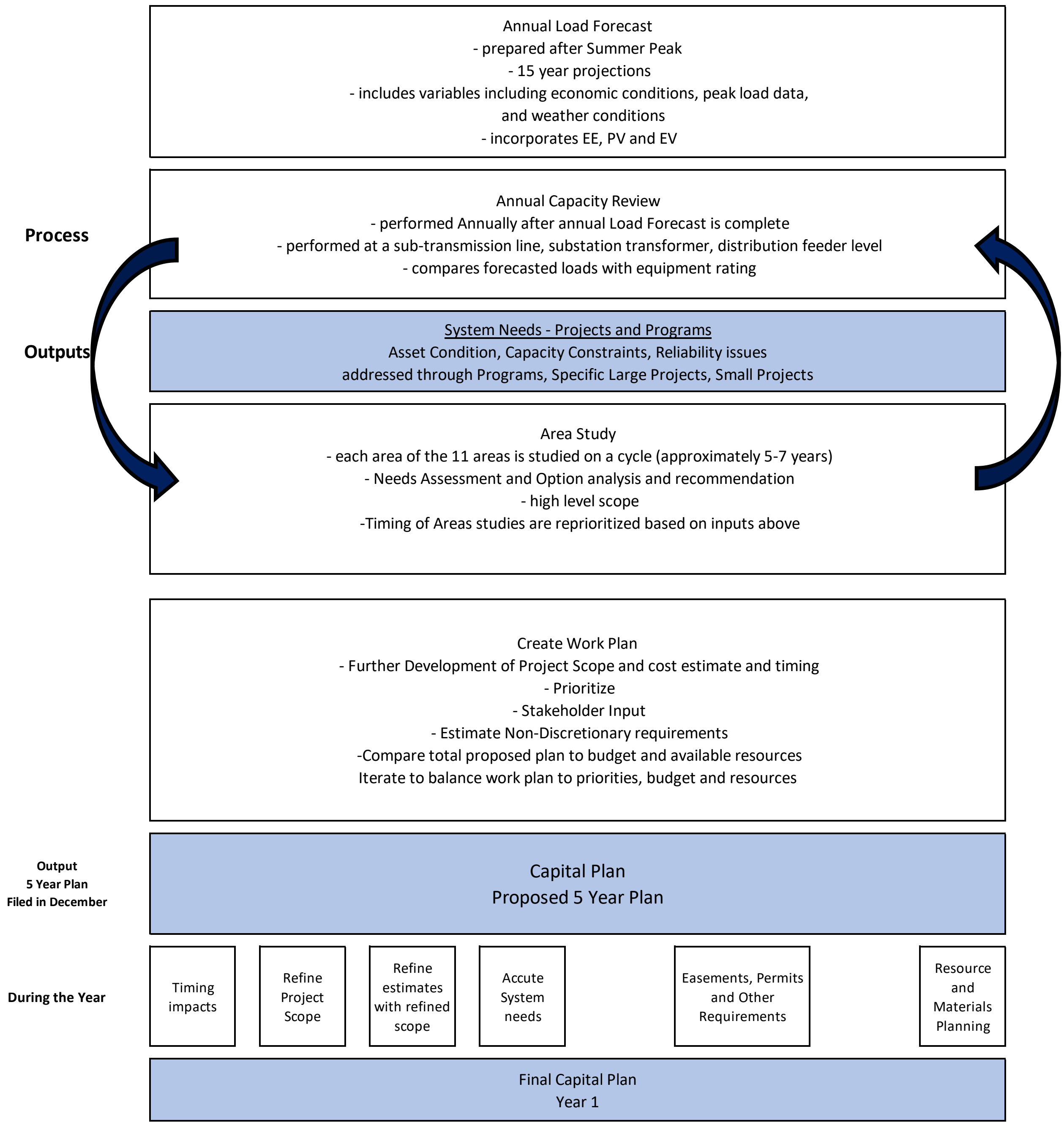
System Planning

Proposed projects to meet system safety and reliability are developed through a pro-active annual capital work plan process. The Company relies on comprehensive planning guidelines combined with detailed system reviews to determine annual investment requirements. The planning process for the ISR Plan takes place over many months and is a dynamic and iterative process that involves multiple cross-functional teams. The work plan is continually updated for future years based on issues identified on the system, changing circumstances, and outcomes of area studies.

Each year the Company prepares a load forecast and conducts routine system analyses on its distribution system. These include capacity reviews and other integrated planning analyses. The Company uses a study area-based approach for planning and project evaluation. The study process ensures alignment between issues and solutions with incorporation of existing strategies and internal design criteria.

Below, Chart 2 depicts the Company's processes from planning to completion for electric capital work. Additional detail is provided in the following sections.

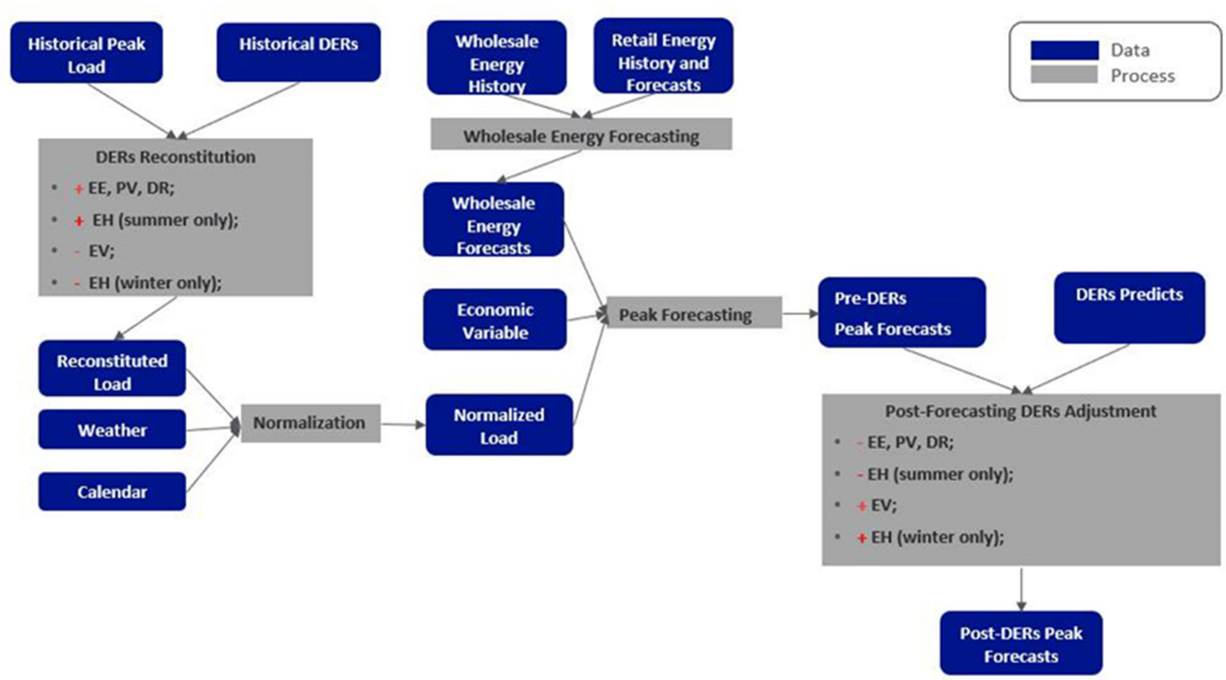
Chart 2
Capital Work Plan Process



Load Forecasting

The Company uses a regression-based core model to forecast summer and winter peak loads. Forecasts are developed annually and have 15-year projections. The explanatory variables being considered and evaluated in this model include historical and forecasted economic conditions specific to Rhode Island, historical peak load data, annual energy sales, and weather conditions based on historical data from the Providence weather station. The chart below shows the data and process flows associated with forecasting load.

Chart 3
Load Forecasting Process



This model is used to predict the forecasted peak demand for the State under a normal and extreme weather scenario. The normal weather scenario assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand under extreme weather conditions. This scenario infers that there is a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

The forecast of peak load incorporates distributed energy resources ("DER"), including energy efficiency ("EE") savings, solar-photovoltaics ("PV") reductions, electric vehicle ("EV") increases, electric heat pumps ("EH") decrease in summer and increase in winter, and demand response ("DR") reduction achieved through 2021 since these impacts would be reflected in the historical data used by the model. The Company considers these DER impacts cumulative through 2021 and the projected incremental DER impacts in the peak load forecasting. The cumulative EE savings, PV reductions, EH reduction in summer, and DR reduction are subtracted from the forecasted peak, and the EH impacts in winter and EV impacts are added to the peak forecasts. A base case is developed for each DER item using its own recent trend, approved programs, and studies as appropriate. The combination of the base cases from these DER items is considered as the base DER scenario and is considered as the most probable scenario at this time. Scenarios of varying levels and types of DER adoption are also developed to provide additional insights into what loads could look like under different scenarios. System Planning used the load with base DER scenario projections from the most recent load forecast for System Capacity and Area Planning Reviews as well as the Grid Modernization Plan. The Company's 2022 peak forecast report is available on the Rhode Island System Data Portal, and the direct link is:

http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2022_Report.pdf

Annual Capacity Review

Actual feeder peak load values from the prior year, along with forecast information described above, are the basis for the capacity reviews. Capacity reviews are completed annually. They identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies. The capacity planning process includes the following tasks:

- Review historic loading on each sub-transmission line, substation transformer, and distribution feeder.
- Apply and evaluate impacts of the weather adjustment on recent actual peak loads as per the Electric Peak (MW) Forecast.
- Apply and evaluate impacts of the econometric forecast of future peak demand growth as per the Electric Peak (MW) Forecast.
- Analyze forecasted peak loads with comparison to equipment ratings.
- Consider system operational flexibility to respond to various contingency scenarios.

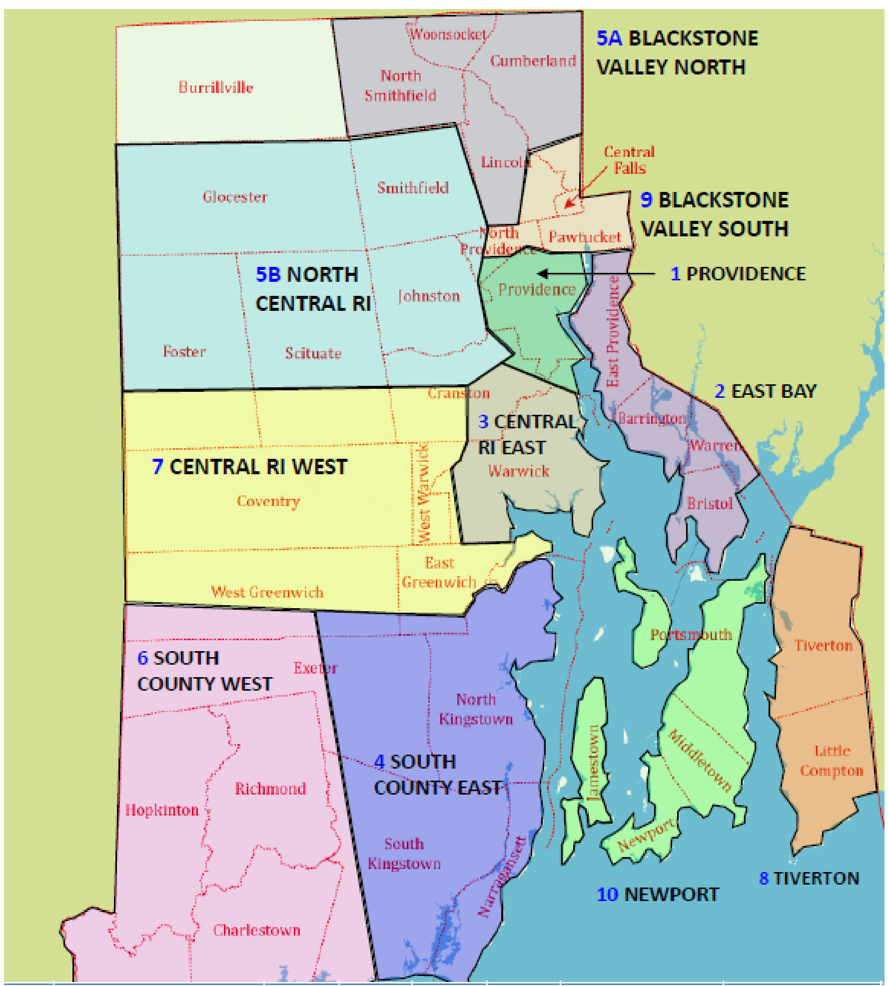
Growth rates are applied to each feeder and sub-transmission line in each area. Specific feeder, sub-transmission line and/or transformer forecasts are adjusted to account for known spot load additions or subtractions, as well as planned load transfers due to system reconfigurations. Feeder/substation forecasted peak loads under the extreme weather scenario are used to perform planning studies and to determine if the thermal capacity of facilities is adequate for future load level projections.

Individual project proposals are identified to address imminent planning criteria violations. At a conceptual level, the Company prioritizes these small-scale project proposals and submits them for inclusion in future year capital work plans. This is the type of work that could generally arise during the Plan year. In addition, during each year's capacity review, the implementation schedule of large projects recommended through Area Planning Studies is assessed and adjusted if conditions indicate an adjustment is needed. This process validates and confirms the need date and implementation schedule of capacity related projects before inclusion in the ISR Plan. The Company anticipates completion of 100% of the annual capacity reviews February 2023.

Area Planning Studies

In addition to identifying imminent issues and corresponding small-scale solutions, annual Capacity Reviews assist in prioritization of the Company's long-range plan which are performed through a series of Area Planning Studies. Area Planning Studies, also known as Area Studies, are more comprehensive technical reviews of the areas within the Company's service territory. Area Study outcomes result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15-year period. Outcomes are proposed in the ISR Plan or, for non-wires alternatives, in the System Reliability Procurement ("SRP") plans. The chart below shows the Company's regional boundaries and study areas. The table shows the high-level evaluations and resolutions resulting from capacity reviews or completed area planning studies.

Chart 4
Area Planning Summary



1 PROVIDENCE
Concerns: asset condition concerns and capacity to supply load growth in an urban environment.
Summary of Recommended Solutions:
- Address the asset condition issues through expansion of the 12.47kV distribution system and conversion of the majority of the 11.5kV and 4kV distribution feeders.
- Study completed May 2014

2 EAST BAY
Concerns: normal and contingency capacity issues and asset condition concerns.
Summary of Recommended Solutions:
- Address asset condition concerns and capacity concerns by expanding the 12kV system and converting the 23kV and 4kV distribution feeders.
- Study completed August 2015.

3 CENTRAL RI EAST
Concerns: normal and contingency capacity issues; long term capacity plan needed to supply eastern Warwick; flood risk at Sockanosett; contingency issues at Kilvert St.
Summary of Recommended Solutions:
- Ongoing Kilvert St substation project will address contingency issues.
- Construction of new Auburn 115/12.47kv substation.
- Study completed February 2017.

4. SOUTH COUNTY EAST
Concerns: potential feeder MWh violations and potential MWh violations at Tower Hill.
Summary of Recommended Solutions:
- Build a new 115/12.47kV substation at existing Lafayette substation site.
- Study completed September 2017.

5A. BLACKSTONE VALLEY NORTH and 5B NORTH CENTRAL RI (Northwest RI)
Concerns: Blackstone Valley North - contingency MWHR violation on the Nasonville Substation; asset condition concerns at Centredale and Greenville; municipal electric stakeholder.
North Central RI - normal and contingency capacity issues and asset condition concerns.
Summary of Recommended Solutions:
- Build a second transformer at Nasonville.
- Rebuild the Centredale Substation to a 12kV substation.
- Study completed March 2021.

6. SOUTH COUNTY WEST
Concerns: normal and contingency capacity issues; flooding concerns at Westerly Substation; Westerly Substation islanded in terms of phasing from surrounding area; asset condition concerns with Wood River and Westerly.
Summary of Recommended Solutions:
- Address asset conditions at Westerly and Wood River.
- New feeder tie for Kenyon 68F2.
- Add a second transformer at the Chase Hill substation.
- Create new feeders tie for Langworthy 86F1.
- Study completed October 2021.

7. CENTRAL RI WEST
Concerns: several circuits require reconductoring due to reliability, contingency, capacity, or asset condition concerns (2230 line, 54F1, 63F6, etc.); asset condition concerns at Coventry, Hope and Division St.
Summary of Recommended Solutions:
- Replace equipment with concerns at Anthony, Natick and Warwick Mall, and complete reconductoring on the 2230 and 2232 23kV lines.
- Extend portions of the 35kV system and install a new modular substation Pine Hill Sub. This new circuit will relieve the 54F1 and 63F6 circuits.
- Study completed May 2021.

8. TIVERTON
Concerns: feeders exceeding 90% of thermal rating; contingency capacity issues on transformer and feeder level; reliability issues due to bare open wire construction in heavily treed areas of Little Compton; asset condition concerns.
Summary of Recommended Solutions:
- Address asset conditions at Tiverton Substation
- Extend the proposed 33F6 circuit further south to address normal and contingency loading concerns.
- Study completed May 2021

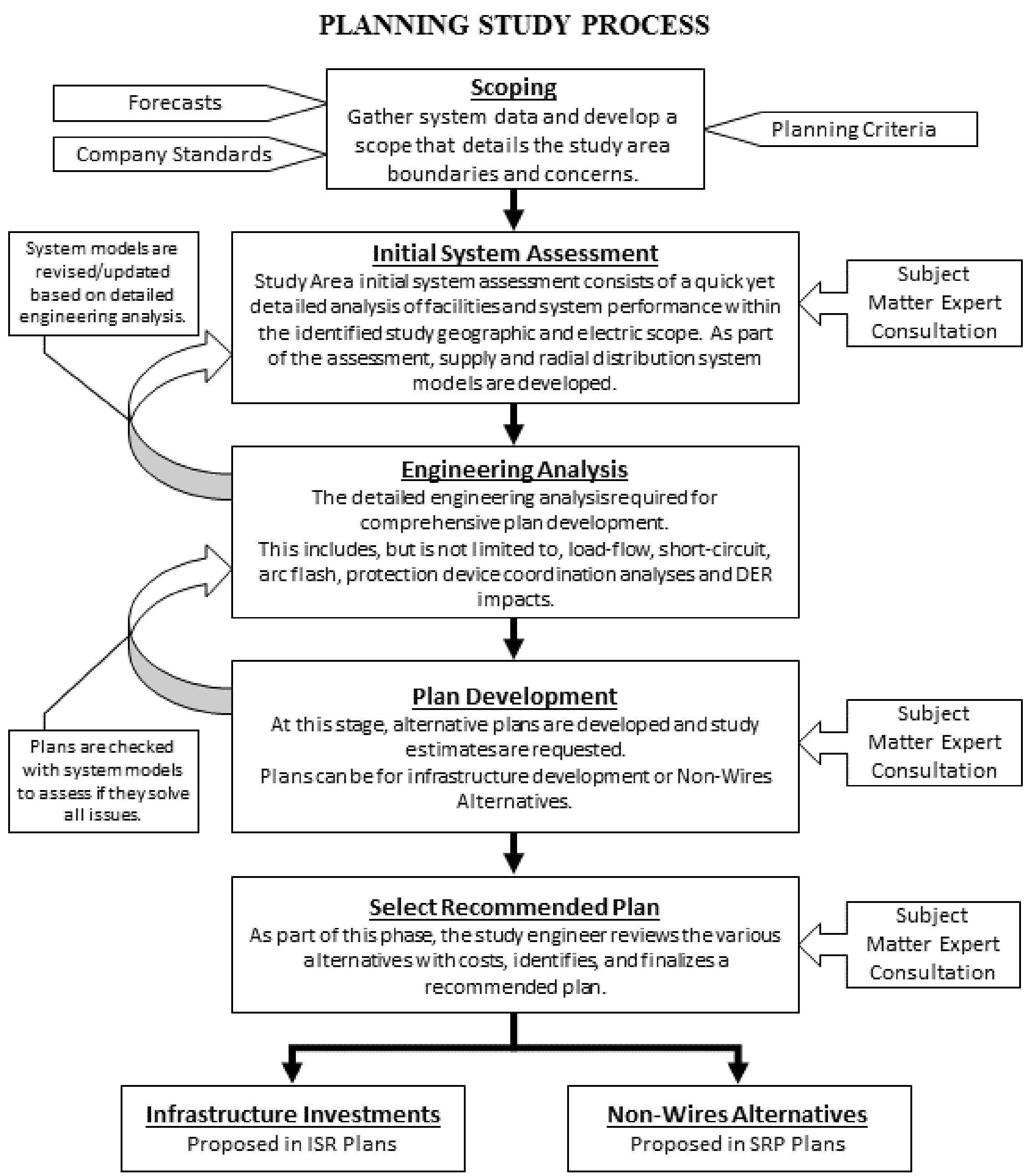
9. BLACKSTONE VALLEY SOUTH
Concerns: asset condition concerns at Pawtucket No. 1 indoor substation; asset condition concerns at Pawtucket No. 2 indoor substation, Valley substation and Washington substation and remaining 4kV substations; minor normal and contingency capacity issues at Pawtucket No. 1, Valley, Washington, and Staples Substations.
Summary of Recommended Solutions:
- On-going Southeast substation project will address some asset and capacity issues at Pawtucket No 1.
- Retire the 4kV substations to address asset condition concerns.
- Study completed October 2021.

10. NEWPORT
Concerns: recently completed Newport and Jepson Substations resolved many capacity and asset condition concerns; sub-transmission normal and contingency capacity issues; asset condition issues at 23kV supplied substations (Kingston, Merton, etc.).
Summary of Recommended Solutions:
- Address safety and asset conditions issues identified in study.
- Utilize existing spare conduit to create parallel cables and increase system capacity to address the 37K22 23kV system concerns.
- Study completed December 2021.

Area Planning Studies enhance the ability to meet obligations to provide safe, reliable, and efficient electric service for customers at reasonable costs. The studies typically address issues in a 10- to 15-year window and typically start five to seven years after the last study was completed. Commencement dates may change based on various system assessments that inform the prioritization of future studies. The study process will continue to be used to develop comprehensive area plans in parallel with existing and emerging program work and other discretionary work the Company considers necessary. The Company completed all Area Studies by December 2021. Completed studies have been provided to the Division and, after review for Critical Energy Infrastructure Information or other confidential information, will be available in the "Company Reports" section of the Company's Rhode Island System Data Portal using the following link: https://ngrid.apps.nationalgrid.com/NGSysDataPortal/RI/index.html

The Company has developed guidelines for the consideration of non-wires alternatives ("NWA's") in the distribution planning process that are incorporated into Area Planning Studies. The goal of these guidelines is to develop a combination of wires and non-wires alternatives that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. See separate discussion of NWA's later in the Plan material.

Chart 5
Area Planning Study Process



See Chart 6 below for the Area Planning Study Status and Statistics

Chart 6
Study Areas Statistics

Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Capacity Review % Complete	Area Planning Study % Complete	Study Completion Date
Providence	358	19%	93	16	100%	100%	May 2014
East Bay	147	8%	22	7	100%	100%	August 2015
Central RI East	204	11%	37	9	100%	100%	September 2017
South County East	159	9%	22	10	100%	100%	March 2018
Blackstone Valley North	139	8%	27	6	100%	100%	March 2021
North Central RI	269	15%	35	10	100%	100%	March 2021
South County West	98	5%	14	5	100%	100%	October 2021
Central RI West	167	9%	29	10	100%	100%	May 2021
Tiverton	36	2%	4	1	100%	100%	May 2021
Blackstone Valley South	171	9%	54	8	100%	100%	October 2021
Newport	105	6%	42	11	100%	100%	December 2021
Totals	1,853	100%	379	93	100%	100%	

Non-Wires Alternatives

During Stage 5 of an Area Planning Study, projects are screened for non-wires alternatives ("NWA"). If a project passes the NWA screening, development of the wires and NWA solutions is done in parallel, prior to advancing either solution through the ISR or System Reliability Procurement ("SRP") plans. Once all alternatives have been evaluated and viable bids are received for any NWA option, the least cost, fit-for-purpose option will be selected. If the NWA option is selected as the recommended plan, it will advance through SRP and no wires alternative will be included in the ISR. If the wires solution is selected as the recommended plan, it will advance through the ISR, with no NWA included in the SRP. Only one alternative will be selected and progressed, either through the SRP or the ISR. In accordance with the Least Cost Procurement ("LCP") Standards,[4] the Rhode Island NWA screening criteria has been proposed through the Three-Year SRP Plan. The 2021-2023 SRP Three-Year Plan was filed with the Commission on November 20, 2020 in Docket No. 5080.[5]

NWAs, like other SRP investment proposals, are progressed for regulatory review in accordance with the LCP Standards. The LCP Standards provide that the Commission prefers that SRP investment proposals be filed alongside, but separately from, annual ISR Plans. Please refer to Section 1 of the 2021-2023 SRP Three-Year Plan document for a summary of the proposals and commitments in the SRP program.

Chart 7 below shows the projects in the Electric ISR Plan that originated from an area planning study or a study from previous legacy planning processes. More detailed descriptions of these projects are included in the Summary of Investment Plan by Key Driver section of the Plan.

[4] The LCP Standards were approved and adopted pursuant to Order No. 23890 in Docket No. 5015 and may be found at: http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf

[5] Please see Section 7.2 of the 2021-2023 SRP Three-Year Plan. http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

Chart 7
Large Projects and Associated Area Planning Studies

Project	Respective Planning Area Study
Southeast (aka Dunnell Park)	Legacy Project - Blackstone Valley North
Dyer Street - Indoor Substation	Legacy Project - Providence System Area Study
Providence Study Projects - Phase 1-4	Providence
Apponaug Substation	Central Rhode Island East
Phillipsdale Substation	East Bay
Centredale Substation	Northwest Rhode Island
Tiverton Substation	Tiverton
Aquidneck Island (Newport projects)	Legacy Project - Newport
New Lafayette Substation	South County East
Warren Substation	East Bay
East Providence Substation	East Bay
Nasonville Substation	Northwest Rhode Island
Weaver Hill Road Substation	Central Rhode Island East

Additional Planning Analyses

Annual capacity reviews are the basis for load flow planning models that are used for many different types of planning analysis. Additional planning activities include, but are not limited to,

- Distributed Generation ("DG") System Impact Studies ("SIS")
- Large new customer load request reviews
- Acute reliability and/or voltage issue reviews
- Operations and Control Center support
- Arc flash/fault duty customer requests

Grid Modernization

Significant changes are occurring across Rhode Island Energy's system as a result of the State's clean energy goals for achieving net-zero carbon emissions by 2050, driving towards 100 percent renewable energy by 2033, all amidst changing customer behaviors and expectations. These changes are marked by the increasing adoption of additional renewable generation sources referred to as distributed energy resources ("DERs"). In addition, there is a rapid growth in beneficial electrification, EVs, electric heat pumps, and advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business. These trends are causing a shift from what traditionally was solely a one-way flow of electricity from the utility distribution system to the customer, to two-way power flow.

While a radial one-way power flow model has served Rhode Island well for many years, conditions on the distribution system are changing rapidly. DERs, which primarily include commercial and residential solar PV and batteries, are being located across the distribution system at a rapid pace. Additional factors adding complexity to the operation of the distribution system are EV charging, electric heat pump conversions, needed reliability improvements, robust VVO/CVR systems and established time varying rates for consumers. These factors are affecting the seasonal and daily variability of demand and must be met in a safe and reliable manner by the electric distribution system. This new and growing complexity requires visibility, situational awareness and increased control of the distribution network that is aided by automation and software to manage the system in a much more dynamic manner.

The Company's system operators will need these enhanced capabilities to ensure safe and reliable operations as customers feel empowered to make more informed decisions and take control of their energy usage. The Company's Advanced Metering Functionality ("AMF") meters and associated systems (filed in a separate Docket) are foundational investments for grid modernization that provide data to update the network model every 45 minutes during the day (as opposed to monthly data in the past). AMF technology will be used to establish a physical network that along with grid modernization field devices and new control center operational systems will enable operators to remotely visualize the distribution system, predict operational issues and take correct actions before they occur. It will also allow operators to respond to sudden outages and restore service more rapidly, minimize curtailment of DERs, reduce peak demand, and avoid other major capital costs for infrastructure.

In its written order in Docket No. 5114,[6] the Commission recognized the importance of grid modernization to meeting the State of Rhode Island's clean energy goals. Investments that fall under the grid modernization framework are being introduced in this ISR Plan to convey that the Company is fully committed to re-constructing the grid to meet the 21st century energy needs. The Company is in the early conceptual planning stages, offering transparency and seeking directional alignment. GMP estimates are just that, estimates that will evolve and become

[6] The Company, while under the control of National Grid, filed a Grid Modernization ("GMP") in Docket No. 5114, on January 21, 2021, with the Commission. On June 29, 2021, the Commission stayed the filing, pending further consideration following the Division's issuance of a final Order in Docket No. D-21-09, Petition for Authority to Transfer Ownership of Narragansett Electric Company to PPL Rhode Island Holdings, LLC. The Company, under the control of PPL, anticipates filing a GMP no later than December 30, 2022.

increasingly accurate as the planning and engineering process proceeds. Lead time for equipment is continuing to get longer, and the Company believes that there is an urgency to move forward with installations. Now under the control of PPL, which has experience with the proposed solutions, the Company understands the benefits and believes that time is of the essence to implement grid modernization to reliably, safely, and affordably serve RI customers while effectuating clean energy objectives.

The 21-Month Plan includes key investments that will provide real-time voltage, current, and power flow data coupled with field devices that can remotely monitor and control the distribution system in real time to maintain reliability (e.g., visualize system violations, adjust voltage, isolate faults, switch load to alternate feeders, correctly provide system protect during back flow conditions, etc.). These investments need to be deployed as soon as possible to address current and future safety and reliability needs on the Company's electric distribution system. GMP investments are being categorized as Non-Discretionary spending because they are needed as components that work together holistically as GMP foundational investments to provide the highest overall net benefits to achieve functionality required to meet operational, customer and clean energy needs. Furthermore, during its review of the Company's FY 2021 Electric ISR Plan, the Commission found that similar investments necessary to operate the electric distribution system should be considered non-discretionary.

Docket 4600 Analysis

The Electric ISR Plan is developed to advance many of the goals for the electric system that the Commission adopted in Docket No. 4600A – Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company, dated October 27, 2017 (the Guidance Document). These goals are:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels).
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.
- Address the challenge of climate change and other forms of pollution.
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides 8 recognizable net benefits.
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.
- Appropriately charge customers for the cost they impose on the grid.
- Appropriately compensate the distribution utility for the services it provides.
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

See Docket 4600 Analysis included in Attachment 5. Investments in grid modernization assets and technology will have a separate benefit-cost analysis using the Docket 4600 framework and will be completed in a separate GMP filing that will be filed in December 2022.

21-Month Capital Investment Plan

The system planning and work development process results in the Company's Capital Investment Plan that will enable it to continue to deliver safe, reliable, and efficient electric service for customers at reasonable costs. As such, the Company presents the following capital spending plan for the 21-month period ending December 31, 2024. As shown in Charts 8 and 9 below, the Company plans to invest $147.4 million during the nine months ending December 31, 2023 and $180.4 million during the twelve months ending December 31, 2024 to maintain the safety and reliability of its electric delivery infrastructure.

Chart 8
Capital Spending by Category FY 2012 – CY 2024
($000)

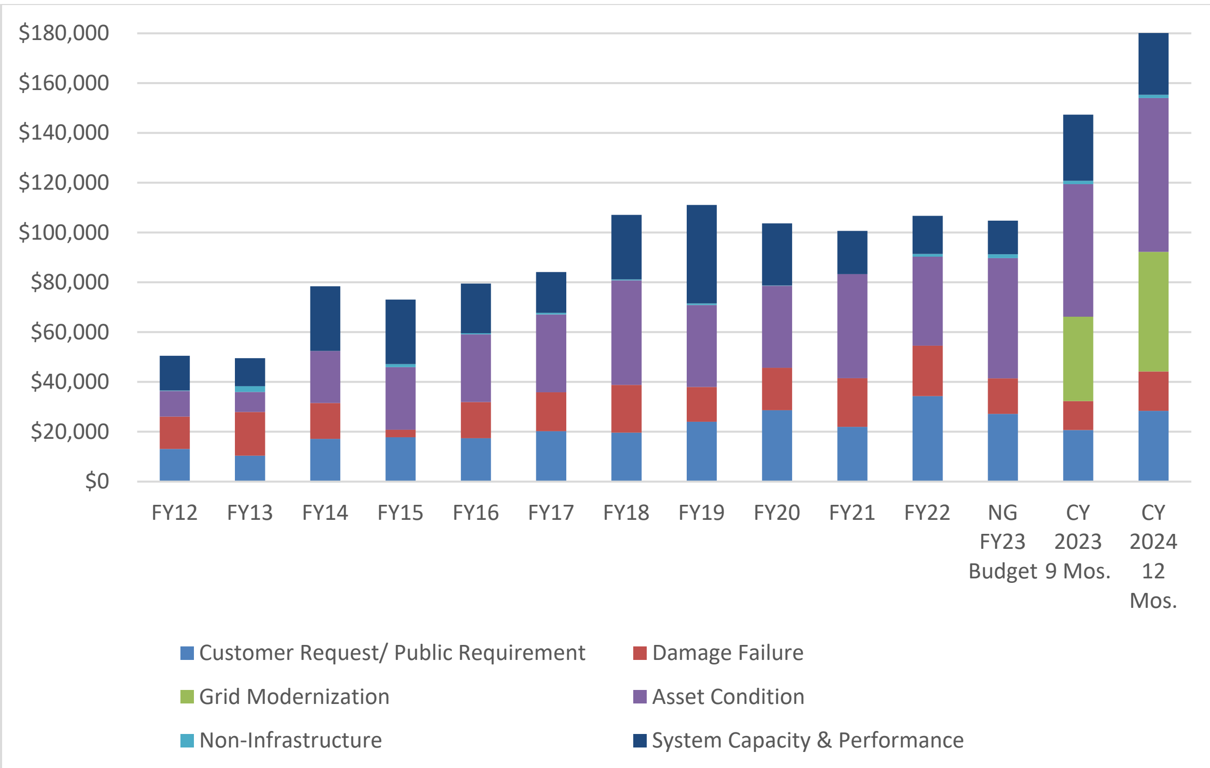


Chart 9
Capital Spending by Category FY 2012 – CY 2024
($000)

Spending Rationale	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	NG FY23 Budget (Dkt. 5209)	CY 2023 9 Mos.	CY 2024 12 Mos.
Customer Request/ Public Requirement	$13,075	$10,410	$17,138	$17,760	$17,412	$20,233	$19,627	$23,989	$28,667	$21,990	$34,335	$27,183	$20,683	$28,357
Damage Failure	12,993	17,515	14,374	3,044	14,531	15,614	19,184	13,999	17,028	19,491	$20,200	$14,251	$11,651	15,878
Grid Modernization	0	0	0	0	0	0	0	0	0	0	$0	$0	$33,877	47,983
Asset Condition	10,320	8,071	20,905	25,141	27,179	31,274	41,978	32,897	32,878	41,816	$35,792	$48,289	$53,193	61,800
Non-Infrastructure	149	2,269	(346)	1,216	457	622	363	673	145	(57)	$1,100	$1,520	$1,375	1,289
System Capacity & Performance	13,995	11,249	25,972	25,890	19,920	16,371	25,906	39,515	24,958	17,387	$15,303	$13,508	$26,586	25,098
Total Capital Spending	**$50,532**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$103,676**	**$100,627**	**$106,730**	**$104,750**	**$147,365**	**$180,405**

Since a portion of the proposed capital spending in this Electric ISR Plan is for projects that will be completed over multiple years, the Company anticipates that only a portion of capital spending will be placed in service during the 21 months ending December 31, 2024. Likewise, a portion of the capital that will be placed in service during the 21-month period will reflect prior years' capital spending for similar multi-year projects. Chart 10 below provides actual and forecasted plant in service additions for FY 2012 through the proposed 21-Month Plan.

Chart 10
Plant in Service FY 2012 – CY 2024
($000)

Spending Rationale	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Actual	FY 2022 Actual	NG FY 2023 Dkt.5209	CY 2023 9 Mos.	CY 2024 12 Mos.
Customer Request/ Public Requirement	$15,144	$11,262	$13,845	$18,443	$19,594	$14,959	$20,825	$24,011	$29,730	$16,761	$25,317	$27,143	$21,293	$23,890
Damage Failure	13,628	12,173	16,928	3,804	16,371	13,635	15,085	16,172	18,035	19,684	21,246	15,971	12,078	17,808
Grid Modernization	0	0	0	0	0	0	0	0	0	0	0	0	5,660	55,039
Asset Condition	13,019	6,638	14,640	28,094	18,533	18,726	44,645	36,599	23,870	46,730	29,872	48,224	23,109	43,465
Non-Infrastructure	60	113	1,990	346	111	0	3	0	194	197	806	1,427	1,132	1,386
System Capacity & Performance	9,799	14,145	8,727	25,970	16,845	28,170	12,103	34,461	33,081	33,114	11,522	12,498	20,188	10,274
Total Plant in Service	**$51,650**	**$44,331**	**$56,130**	**$76,657**	**$71,453**	**$75,489**	**$92,660**	**$111,243**	**$104,909**	**$116,487**	**$88,763**	**$105,264**	**$83,460**	**$151,862**

Development of Work Plan and Estimating

Each year, the Company develops an Annual Work Plan, which is designed to achieve the Company's overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. The Annual Work Plan represents a compilation of proposed spending for individual capital projects and programs. Projects and programs are categorized as either Non-Discretionary or Discretionary spending. The Non-Discretionary categories, or Spending Rationales, are Customer Requests/Public Requirements, Damage/Failure, and Grid Modernization. The Discretionary categories, or Spending Rationales, are Asset Condition, Non-Infrastructure, and System Capacity and Performance. The proposed spending is forecasted based on the most recent cost and timing estimates for in-progress projects and initial estimates for newly proposed projects.

Under the FY 2022 ISR Plan the Company began experiencing impacts in delivery and costs related to materials and services due to supply chain constraints. The Company is continuing to see longer lead times for materials and has adjusted schedules and business practices to ensure the execution and completion of projects in the FY 2024 ISR Plan.

The 21-Month Electric ISR Plan is the Company's best information regarding the investments needed to sustain the safe, reliable, and efficient operation of the electric system. The Company continuously reviews and updates the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, system operations, performance, safety, updated estimates, and customer-driven needs. In addition to filing Quarterly ISR Plan Reports, the Company has agreed to ongoing collaborative discussions with the Division, including to inform the Division prior to advancing significant (greater than $1 million) unbudgeted projects during implementation of an ISR Plan as suggested in the February 11, 2021 report of Gregory L. Booth, the Division's consultant. There are some projects in the long-term forecast that are in process of having the total project cost estimates revised and the long-term forecast will be updated once those estimates are complete.

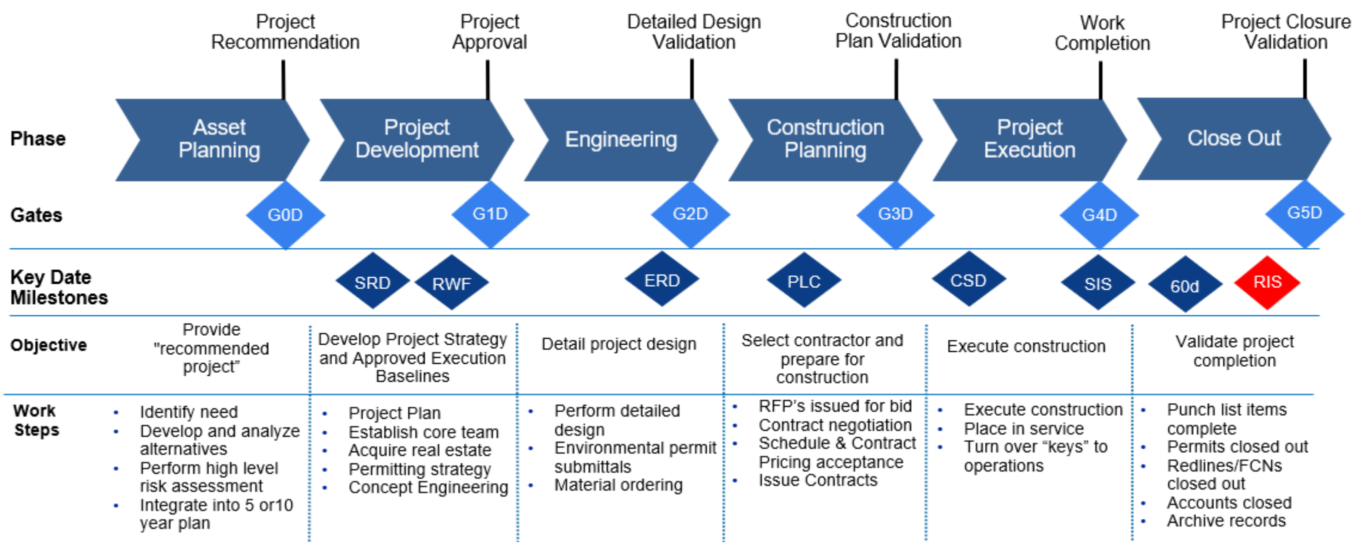
Once the mandatory budget level has been established for the Non-Discretionary spending categories, the Company reviews projects and programs in the Discretionary categories for inclusion in the spending plan. A project risk score is assigned to each project and considers key performance areas such as safety, reliability, and environmental, while also accounting for criticality. While project risks score is a significant criterion, other factors considered in creating the Work Plan include, but are not limited to, new project or in-progress status, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is utilized to optimize cost efficiency and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project. Historical and forward-looking checks are made to identify deviations from expected or historical trends.

The portfolio is presented to the Company's senior executives and approved by the President of The Narragansett Electric Company. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible for managing the approved budget.

Delivering Complex Projects Using the Stage-gate Process

The Company will follow a stage-gate process for the creation, development, and delivery of complex capital projects. The process breaks the typical project life cycle down into six stages as shown on the flowchart below.

Chart 11
Complex Project Delivery Stage-Gate Process



Delegation of Authority and Sanctioning

Delegation of Authority ("DOA") is a financial control and provides a framework to ensure that business decisions are made at an appropriate level with the right authority. For purposes of capital projects, that framework is the sanctioning process. The Company has established DOA approval levels and sanctioning procedures that are undergoing internal approvals. With the Company's new organizational structure, the sanctioning process will be more localized and efficient.

21-Month Proposed Capital Spending Plan

The table below shows the 21-Month ISR Plan's planned investment to maintain the safety and reliability of its electric delivery infrastructure. The section below summarizes the spending by key drivers. Attachment 1 to this section provides spending detail on major project categories that support the proposed level of capital spending by key driver. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available. Attachment 3 includes a summary of information regarding the major multi-year projects.

Chart 12
Proposed 21-Month Capital Spending
($000)

Spending Rationale	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Customer Request/Public Requirement	$27,183	$20,683	$28,357	$49,040
Damage Failure	14,251	11,651	15,878	27,529
Grid Modernization	0	33,877	47,983	81,860
Asset Condition	48,289	53,193	61,800	114,993
Non-Infrastructure	1,520	1,375	1,289	2,664
System Capacity & Performance	13,508	26,586	25,098	51,684
Total	**$104,750**	**$147,365**	**$180,405**	**$327,770**

The Company considers the investment required to comply with customer requests and statutory and regulatory requirements, including meeting State clean energy goals, and to fix damaged or failed equipment as mandatory and non-discretionary in terms of scope and timing. Together, these items total $66.2 million during the nine months ending December 31, 2023 and $92.2 million during the twelve months ending December 31, 2024 and represent 48% of the Plan's proposed capital investment.

The Company has slightly more discretion regarding the scope and timing of investment in Asset Condition, Non-Infrastructure, and System Capacity and Performance categories of spending. The Company closely monitors the risk associated with delaying such projects due to the potential impact and consequences of the failure of equipment or systems. The investments the Company will pursue have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the system. Together, these items total $81.2 million during the nine months ending December 31, 2023 and $88.2 million during the twelve months ending December 31, 2024 and represent 52% of the Plan's proposed capital investment.

Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a 21-month budget of $49.0 million to comply with customer requests and statutory and regulatory requirements in the 21-Month Plan. Overall, the scope and timing of this work is defined by those who are external to the Company. Much of the construction work is variable and requested on short notice to account for emergent projects. The budget is set based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget represents the capital the Company expects to spend, net of contributions in aid of construction ("CIAC") and other reimbursements.

The chart below shows a comparison of the 21-Month proposed capital spending to FY 2023's budgeted capital spending for this category.

Chart 13
Proposed 21-Month Capital Spending – Customer Request / Public Requirement
($000)

Customer Request / Public Requirement	**NG FY 2023** Budget (Dkt. 5209)	**CY 2023** 9 Mos. 4/1/23-12/31/23	**CY 2024** 12 Mos. 1/1/24-12/31/24	**21-Month ISR Plan** 4/1/23 - 12/31/24
New Business - Commercial	$8,950	$6,820	$9,366	$16,186
New Business - Residential	7,060	5,409	7,428	12,837
Public Requirements	1,338	937	1,341	2,278
Transformers & Related Equipment	4,800	3,780	5,292	9,072
Meters and Meter Work	2,740	1,971	2,535	4,506
Distributed Generation	1,000	750	1,000	1,750
Other	1,295	1,016	1,395	2,411
Total	**$27,183**	**$20,683**	**$28,357**	**$49,040**

The major components in the Customer Request/Public Requirement category are:

- Responding to new customer requests, including establishing electric delivery service to new customers, Third Party Attachment work, and Distributed Generation ("DG") requests.
- Relocating facilities for public works projects requested by cities and towns and the Rhode Island Department of Transportation. As of June 29, 2022, RIDOT will only be reimbursing the Company for 50% for new projects.
- Transformer, capacitor, regulator, network protectors and meter purchases and installations.
- Outdoor lighting requests and service.

Damage/Failure

For the 21-Month Plan, the Company is proposing a budget of $27.5 million to replace assets that either unexpectedly fails or becomes damaged in the 21-Month Plan. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes. In response to a recommendation made by the Division, the Company created refined definitions for Damage/Failure and Asset Replacement work and established new processes. The Company continues to monitor how the refined definitions and process are impacting spending in this area and asset replacement.

Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historical trends. A reserve is included in the Damage/Failure budget to allow for larger project work due to failed assets that may arise during the year as well as carryover projects from the prior fiscal year where the final restoration of assets will be completed over multiple years. Additionally, the budget includes capital spending to address issues that have been identified for immediate repair as part of the I&M program described in Section 4.

The chart below shows a comparison of the 21-Month proposed capital spending to FY 2023's budgeted capital spending for the Damage/Failure category.

Chart 14
Proposed 21-Month Capital Spending – Damage/ Failure
($000)

Damage/Failure	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Damage/ Failure	$11,576	$8,436	$11,268	$19,704
Nasonville Substation Rebuild	0	1,092	1,637	2,729
Reserves - DF	750	735	1,010	1,745
Storms and Weather Events	1,925	1,388	1,963	3,351
Total	**$14,251**	**$11,651**	**$15,878**	**$27,529**

The major components of the Damage/Failure category are:

- Blanket projects for substation and line failures for small dollar, frequently occurring items or those projects whose size is unknown at the time of the failure.
- A reserve to address larger failures that require capital expenditures in excess of $100,000. The budget for this item is built on recent historical trends of such items and allows the Company to complete unplanned work without having to halt work.

- Storm and weather event activity affects the Company's assets. While the actual spending in this category may vary greatly, this reserve allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

- In the 21-Month Plan, the Company has included $2.7 million related to a the rebuild of the Nasonville Substation. In August 2022, the metal clad switchgear was damaged beyond repair due to a bus fault. The failed switchgear will be replaced with an open air straight bus that will include a main breaker, capacitor breaker, and four feeder breakers. Removal of the failed equipment, design, engineering, and procurement of long lead time materials for the replacement began under the FY 2023 (Docket 5209) Electric ISR Plan. Once materials are received, it is estimated that the work will take six to nine months to complete. The Company is forecasting Damage/Failure spending of $1.2 million in the FY 2023 (Docket 5209) ISR Plan. As a result of this failure, the projects at the Nasonville Substation resulting from the Northwest Rhode Island Area Study will be reassessed.

Grid Modernization

For the 21-Month Plan, the Company is proposing a budget of $81.9 million of Grid Modernization capital spending to meet the evolving operation and reliability needs, customer expectations, and State clean energy goals.

Chart 15
Proposed 21-Month Capital Spending – Grid Modernization
($000)

Grid Modernization	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23- 12/31/23	CY 2024 12 Mos. 1/1/24- 12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
ADMS/DERMS Advanced	$0	$105	$140	$245
Advanced Reclosers	0	17,405	25,264	42,669
DER Monitor/Manage	0	0	0	0
Electromechanical Relay Repl Pgm	0	2,040	2,853	4,893
Fiber Network	0	8,105	11,348	19,453
IT Infrastructure	0	1,514	2,019	3,533
Mobile Dispatch	0	74	98	172
Smart Capacitors & Regulators	0	4,635	6,261	10,896
Total	**$0**	**$33,877**	**$47,983**	**$81,860**

The components of the Grid Modernization category are:

- *Advanced Distribution Monitoring System ("ADMS")* – ADMS is the central linkage between AMF and Grid Modernization. As part of Rhode Island Energy's transition to PPL's system, ADMS Basic, the ADMS platform PPL currently has in place in Pennsylvania, will be provided to Rhode Island Energy for its distribution management system operations. As a condition of the Acquisition approval, PPL committed to not seeking recovery of transition costs from Rhode Island customers. Part of the transition includes utilizing ADMS Basic by Rhode Island Energy. This project proposes enhancements to increase functionalities and benefits. These include the development of advanced ADMS functionality to include FLISR, VVO, Contingency Analysis, Hidden Load Identification, Adaptive Load Shed, and other key features. The project will integrate Distribution Control Center hardware and software that will provide greater visibility, situation awareness, control, and optimization of the electric distribution grid, as well as efficiencies by automating control center processes. The 21-month planned spend for ADMS is roughly 3% of the ADMS 5-year GMP.

- *Advanced Reclosers* – This project proposes targeted investment in both main line and tie point advanced reclosers to reduce duration and frequency of outages. This investment will take into consideration Area Study solutions which may call for the reconfiguration and or conversion of certain circuits. As DER penetration increases, two-way power flow, overloads in the reverse direction under light load conditions, and desensitization of protection systems during fault conditions may result. An increasingly complex grid requires control schemes that are integrated across an entire feeder. When used in combination with ADMS, advanced reclosers allow for load control and near real-time power measurements. This enables automatic fault isolation, service restoration ("FLISR"), and better management of capacity and voltage along individual feeders. This optimization will result in lower costs to customers. The 21-month planned spend is roughly 35% of the Advanced Recloser 5-year GMP plan.

- *DER Monitor Managed* – This spending relates to the installation of smart inverters on DERs that provide two-way communication that allows system operators to monitor and manage DERs interconnected with the distribution system. The inverters have the capability to respond to changes in frequency and other disruptions on the grid and can also be used to stabilize the grid. The 21-month planned spend is roughly 0% of the DER Monitor Manage 5-year GMP plan.

- *Electromechanical Relay Upgrades* – This project proposes to upgrade solid-state, first-generation, electromechanical relays to digital relays over five years. The Company's current relays provide little data or flexibility. Upgraded relays will adapt to system changes and conditions with flexible settings and custom logic. Fault location information will minimize outages and reduce the time field technicians spend searching for issues. The Company's electromechanical relays have been inventoried and categorized based upon upgrade complexity and ease of replacement. There are four categories of replacement. The 21-month planned spend is roughly 23% of the Electromechanical Relay Upgrade 5-year GMP plan.

  - <u>Category 1</u>: These relay replacements will utilize the existing standard where the relays come pre-wired within an outdoor enclosure. Using an existing standard will allow for quick implementation.

  - <u>Category 2</u>: These relay replacements will require a new standard. These relays will be installed within the breaker itself as opposed to being in a separate enclosure.

- Category 3: These relay replacements will require a new standard to be developed and is expected to be finalized after the Category 2 standard. This new standard will be for substations that have indoor circuit breakers and relay panels where a full relay switchboard panel design is required.

- Category 4: These relay replacements will require the station to be rebuilt or relocated due to existing space constraints within the substation yard making it not feasible to replace the relays within the same footprint. Due to the complexity of this work, these relays will be replaced after 2028. This is high level and will be refined as we progress with scope development.

- *Fiber* – This project proposes to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul GMP and AMF data. Leased cellular service has limited bandwidth and is subject to greater interference, especially during emergencies when communication is imperative. The 21-month planned spend is roughly 32% of the Distribution Fiber 5-year GMP plan.

- *IT Infrastructure* – This project proposes to build foundational IT infrastructure investments in data management, enterprise integration platform, and corporate PI historian to enable grid modernization functionalities and realize its full benefits. This project also includes a cybersecurity component and engineering planning tools. The 21-month planned spend is roughly 23% of the IT Infrastructure 5-year GMP plan.

- *Mobile Dispatch* – This project proposes investment in a mobile dispatch system and devices. ADMS-based mobile dispatch allows efficient utilization of field crews based on location, capabilities, and equipment, thereby improving restoration times, accuracy of restoration efforts, and worker safety. The 21-month planned spend is roughly 23% of the mobile dispatch 5-year GMP plan.

- *Smart Capacitors & Regulators – This* project proposes upgrading the Company's existing capacitors and regulators without advanced controls to allow for dynamic adjustment of system voltages to accommodate the variable output of DER, better manage capacity and voltage along individual feeders resulting in lower costs to customers. For optimization in certain areas of the State, additional capacitors and regulators will be installed. The 21-month planned spend is roughly 37% of the smart capacitor and regulators 5-year GMP plan.

Asset Condition

The Company is proposing a 21-month budget of $115.0 million to replace assets due to condition issues. Asset Condition projects and programs have been identified to reduce the risk and consequences of unplanned asset failures and are identified as part of the System Planning process. The focus is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. This investment is essential and is scheduled to minimize the potential for reliability issues. Due to the large number of aged assets in the Company's service area strategies have been developed to replace assets if their condition impairs reliable and safe service to customers. Experience with assets that have poor operating characteristics in the field has led the Company to develop strategies to remove such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with consequences of such an event.

The chart below shows a comparison of the 21-Month Plan proposed capital spending to FY 2023's budgeted capital spending.

Chart 16
Proposed 21-Month Capital Spending – Asset Condition
($000)

Asset Condition	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Large Projects:				
Dyer Street	$3,500	$0	$0	$0
Prov LT Study - Ph1A	1,484	0	0	0
Prov LT Study - Ph1B	16,585	13,580	13,622	27,202
Prov LT Study - Ph2, Ph3, Ph4	1,517	11,279	11,068	22,347
Phillipsdale Substation	0	2,390	2,951	5,341
Centredale Substation	0	1,116	1,750	2,866
Southeast Substation	223	66	0	66
Apponaug Substation	0	763	1,428	2,191
Tiverton Substation	0	85	341	426
Other:				
Underground Cable projects	5,700	5,228	5,178	10,406
URD Cable projects	5,000	6,281	6,374	12,655
Blanket projects	5,160	3,915	5,377	9,292
I&M	3,000	2,256	2,961	5,217
Substation Breakers & Reclosers	2,580	437	0	437
Other Area Study Projects	0	4,319	10,030	14,349
Other projects and programs	3,539	1,478	720	2,198
Total	**$48,289**	**$53,193**	**$61,800**	**$114,993**

The large projects in the Asset Condition category are:

- *Dyer Street Replace Indoor Substation* – In the re-scoped Dyer Street Substation project, an external substation within the existing South Street Substation outdoor yard was built. The work involves the installation of two new 11 kV to 4.16 kV transformers and the corresponding risers and switches, the installation of a metal clad switch gear, and the needed distribution feeder getaways. The Company forecasts that the capital work on this project will be completed and assets will be in service by March 2023. The removal of the AC building will be completed during March 2023. As recommended, the Company tracks this project separately and reports on its progress quarterly.

- *Southeast Substation* – This project addressed asset condition and safety concerns at the Pawtucket No. 1 and the Dunnell Park substations as well as improvements to overall capacity. The substation portion of this project is substantially complete and went into service in March 2021. A significant portion of the distribution line project went into service during FY 2022. Building demolition construction will begin in August 2023. The Company tracks this project separately and reports on its progress quarterly.

- *Providence Long-term Study Projects* – The Providence Area Planning Study identified asset condition issues at five indoor substations and on over 25 miles of underground cable within the study area. The study recommended the expansion of the 12.47 kV distribution system to enable conversion of the majority of 11.5 kV and 4.16 kV load. This allows the elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations and several miles of sub-transmission cable. A large part of the 12.47 kV capacity in the area would be provided by a new 115/12.47 kV station at Admiral Street. This substation will supply the converted load from the Geneva, Harris Avenue, Olneyville, and Rochambeau Avenue substations. The recommendations from the Providence Area Planning Study have been categorized into the phases summarized below:

    - <u>Phase 1A</u> – Rebuilt and converted sixteen 4 kV and 11 kV feeders to 12.47 kV in Providence. Lines are fed from the 12.47 kV Clarkson and Lippitt Hill substations. This will allow loads to be removed from Admiral Street in order to implement Phase 1B. The Company forecasts that the work on this phase will be completed and assets will be in service by March 2023.

    - <u>Phase 1B</u> – Convert 4 kV lines currently fed from Olneyville to 12.47 kV. Install manholes and duct banks for new 12.47 kV feeds from Admiral Street station. Remove the 4 kV and 11 kV equipment from Admiral Street building and demolish the building. Install new 12 kV equipment and building at Admiral Street and energize the new 12.47 kV feeders. This phase is currently in construction.

- Phase 2 – Rebuild and convert sixteen 4 kV and 11 kV feeders at Olneyville, Harris Avenue, Rochambeau, and Geneva substations. Loads will be carried by the new Admiral Street 12.47 kV substation.

- Phase 3 – Retire the 4 kV and 11 kV indoor and outdoor substations at Olneyville, Harris Avenue, Rochambeau, and Geneva substations.

- Phase 4 – Install a 115 / 12.47 kV substation at Knightsville, convert the station feeds to 12.47 kV. Remove and retire the existing 23 / 4.16 kV substation.

As recommended, the Company will track these projects separately and report on progress quarterly. The following projects will be initiated during the 21-month period of the Plan and activities will include engineering, design, and initial procurement of materials.

- *Phillipsdale Substation* – The East Bay Area Study recommended replacing the Phillipsdale Substation and retiring of the Waterman Substation due to reliability issues and the age and condition of assets. Current planning recommends completing the project in two phases. The ultimate build-out will be a 115 / 12.47 kV substation and include two 40 MVA LTC transformers supplying straight-bus metal clad switchgear with a tie breaker, eight feeder positions, and two 7.2 MVAR two stage capacitor banks. In addition, convert the 23 kV sub-transmission system to 12.47 kV.

- *Centredale Substation* – The Northwest Rhode Island Area Study recommended rebuilding this substation and converting the 4 kV distribution loads to allow for retirement of the 4.16 kV equipment.

- *Apponaug Substation* – The Central Rhode Island East Area Study recommended rebuilding this substation with two new 23/12.47 kV modular feeders utilizing standard open air modular feeder construction. Due to a history of operational challenges and asset condition issues, a short-term plan addressed the retirement of the 23 kV station, removal of equipment, and installation of relayed reclosers for transformer protection in previous years.

- *Tiverton Substation* – The Tiverton Area Study recommended the addition of a 12.47 kV breaker, three regulators, and a new getaway manhole and duct system inside the substation in addition to replacement of equipment with asset condition issues.

Other work in the Asset Condition category includes:

- *Inspection & Maintenance Program* – Section 4 includes details related to both the capital and O&M components of the I&M program.

- *Underground Cable Replacement Program* – This program implements the strategy to replace primary underground cable that is in poor condition or has poor operating history. This program targets known problematic cable types such as paper and lead insulated cables and certain cross-linked polyethylene ("XLPE") insulated cables. Underground cable is reactively replaced when it fails, and the spending is categorized as non-discretionary spending in the Damage/Failure spending rationale. Proactive replacement of underground cable is included in the Asset Condition spending rationale and prioritized based on type of construction, asset condition, and failure history for a specific or similar asset. Proactive replacement work is justified by the need to eliminate repeated in-service failures, anticipated end-of-life based on historic performance or industry experience, or other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. The underground cable replacement program prioritizes the cables using a risk matrix focused on cable characteristics.

- *URD Cable Program* – The replacement of Underground Residential Development ("URD") and Underground Commercial Development ("UCD") cables sized #2 and 1/0. These cables are replaced or rehabilitated through cable injection. This strategy supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although interruptions on #2 and 1/0 cables do not significantly influence Company level service quality metrics, they can have significant localized impacts on effected neighborhoods. For URDs with at least three cable failures within the last three years, two options are considered for replacement. Insulation injection is identified as the preferred solution for direct buried Cross Linked Polyethylene cables in a loop fed arrangement. The overall condition of the primary and neutral cables and installation specifics determine if insulation injection is a viable option. This strategy does not apply to mainline or supply cables.

- *Network Blower Motor Program* – This program replaces network vault blower motors with arc resistant motors, predominantly located in Pawtucket and Providence. Approximately half of the locations with blower motors will require civil work to allow installation of the Company's standard arc resistant motor and vent system. The Company anticipates that this program will close by December 2026.

- *Distribution Substation Battery Replacement Program* – Battery systems play a significant role in the safe and reliable operation of substations. The batteries and chargers provide direct current power for protection, control, and communications within the substation, as well as communication between the substation and the Company's operational control center. Program goals include the replacement of batteries to ensure that battery systems meet the current operating requirements and perform their designed functions. In the 21-month plan, the Company plans to replace eight station batteries as it optimizes the replacement schedule with risks and upcoming projects.

- *3763 Line Structure Replacements* – Based on an assessment performed in 2020, eleven concrete structures on the 69 kV 3763 Line in Newport, RI will be replaced due to structure deficiencies and asset condition issues. This project was proposed in the FY 2023 ISR Plan and was delayed due to material delivery delays and inability to complete the project during winter months. Capital spending of $0.8 million was shifted to the 21-Month ISR Plan. This project is forecasted to be completed by December 2023.

- *Blanket Projects* – In addition to specific projects, the Company establishes asset replacement blanket projects to ensure that local field engineering and operations can resolve asset condition issues (i.e., deteriorated equipment) in an efficient and effective manner. The amount of funding in the blanket project is reviewed and approved each year based on historical trends in the volume of work required, input from local Operations, and forecasted impact of inflation on material and labor rates. The individual work requests have a value of less than $100,000. Current year spending is monitored on a monthly basis.

System Capacity and Performance

The Company is proposing a 21-month budget in the Plan of $51.7 million for System Capacity and Performance investments. The Company has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers. Projects in this category are identified through the Company's planning processes that are conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies. Individual project proposals are identified to address planning criteria violations. At a conceptual level, the Company prioritizes these project proposals and submits them for inclusion in future capital work plans. It is important to recognize that these investments may also have asset condition drivers that influence replacement decisions.

The chart below shows a comparison of the proposed budget to FY 2023's capital spending.

Chart 17
Proposed 21-Month Capital Spending – System Capacity and Performance
($000)

System Capacity and Performance	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Large Projects:				
Aquidneck Island	$730	$1,038	$0	$1,038
New Lafayette Substation	2,914	750	748	1,498
Warren Substation	1,824	1,969	3,376	5,345
Nasonville Substation	0	1,912	3,604	5,516
East Providence Substation	2,495	1,233	4,449	5,682
Tiverton Substation	0	64	291	355
Weaver Hill Road Substation	0	1,162	1,852	3,014
Chase Hill Substation	0	0	715	715
Other Projects and Programs:				
3V0	740	825	945	1,770
EMS/RTU	1,165	603	407	1,010
OH Line Transformer Repl	1,500	1,094	958	2,052
Blanket Projects - SCP	2,030	1,992	2,737	4,729
Other Area Study Projects	0	2,834	2,636	5,470
Mainline Recloser Enhancements	0	9,504	0	9,504
CEMI-4 Program	0	820	1,640	2,460
Other projects and programs	109	786	740	1,526
Total	**$13,508**	**$26,586**	**$25,098**	**$51,684**

The major projects in the System Capacity and Performance category are:

- *Aquidneck Island Projects:* These projects included construction of a new 69 / 13.85 kV substation and related line work to provide load relief to the City of Newport; rebuilding the Jepson substation in Middletown; and the demolish and reconstruction of the Dexter Substation. This work is essentially complete and was placed into service during FY 2020 through FY 2022. The remaining work includes minor improvements to certain substations.

- *New Lafayette Substation:* A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. The study identified several reliability and asset condition issues. The study recommends building a new open air, low profile, breaker-and-one-half 115/12.47 kV substation at the existing Lafayette substation site. The existing 34.5/12.47 kV station at Lafayette will be retired once the new station is placed into service. The schedule for this project has been adjusted due to transmission outage coordination issues.

- *Warren 115/12.47 kV Substation:* The Warren #5 substation expansion project has been recommended as part of the East Bay Long Term Study. The project expands the existing substation by adding two new 12.47 kV feeders, a new substation capacitor, and new distribution construction to provide additional capacity to Warren and Barrington. In order to provide additional capacity to the Warren and Barrington area, distribution construction requires the crossing of the Barrington and Palmer Rivers in conjunction with on-going projects with RIDOT along the East Bay Bike Path. Completion of the project facilitates the retirement of the Barrington substation, which has safety and asset condition concerns, the capacity constrained Mink 115/23 kV substation, and a significant portion of the 23 kV sub-transmission in the area.

- *East Providence Substation:* The East Bay Long Term Study identified asset condition and loading concerns in the East Providence area. The study proposed a new station in the East Providence area that will reduce the loading and dependence on the 23 kV sub-transmission system. This project involves the construction of a new 115/12.47 kV substation adjacent to the 115 kV transmission right-of-way. The project requires a tap structure and easement within the public right of way to the 115kV transmission right-of-way. Construction will consist of a 40 MVA LTC transformer supplying straight-bus metal-clad switchgear with a tie breaker, six feeder positions, and two two-stage capacitor banks.

The following projects will be initiated during the 21-month period of the Plan and activities will include engineering, design, and initial procurement of materials.

- *Nasonville Substation* – The Northwest Rhode Island Area Study recommended bringing a new 115 kV overhead supply line from Woonsocket substation to Nasonville substation and adding a second transformer and straight bus to the existing Nasonville substation.

- *Weaver Hill Substation* – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder.

Additional investments in the System Capacity and Performance category are:

- *Mainline Recloser Enhancements* – The Plan proposes capital spending to install reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts. The absence of reclosers on exposed overhead lines and circuits with one or zero reclosers increases customer outages due to the lack of sectionalization and reduces the ability to remotely transfer load during an outage. All reclosers will use the latest control technology aligned with the pending Grid Modernization Plan ("GMP") and location selection will be aligned with ultimate GMP implementation. The Company proposes capital spending in the 21-Month Plan to install approximately 100 mainline reclosers.

- *3V0 Program:* As DG penetration levels continue to increase, the need for zero sequence overvoltage ("3V0") protection is more necessary. The addition of DG to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. To enable a more rapid response to DG interconnections, the Company proactively installs 3V0 protective devices in substations on a priority basis. The 21-Month ISR Plan proposes capital spending to install four 3V0 devices. Devices will be installed on the Clarke Street and Natick Substations during the first nine months of the Plan. The Company will reevaluate when these projects are complete to identify two additional substations based on highest need.

- S*ubstation EMS/RTU (SCADA) Additions Program:* The Company is proposing to continue the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies.

- *Volt/VAR Optimization and Conservation Voltage Reduction ("VVO"/"CVR") Pilot*: The Company is proposing no capital spending in its 21-Month ISR Plan. As discussed in Section 4, this project has ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing. Refer to the Advanced Capacitors and Regulators section in the Grid Modernization portion of the document for future VVO plans.

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

- *Blanket Projects:* In addition to specific projects, the Company also establishes blanket projects to ensure that local field engineering and operations can resolve system and equipment loading and reliability issues in an efficient and effective manner. The amount of funding in the blanket project is reviewed and approved each year based on the results of annual capacity planning and reliability reviews, historical trends in the volume of work required, input from local Operations, and forecasted impacts of inflation. The individual work requests have a value of less than $100,000 in value. Current year spending is monitored on a monthly basis.

Non-Infrastructure Spending

The non-infrastructure category is for those capital expenditures that do not fit into one of the above-mentioned categories. This capital spending is necessary to run the electric system, such as general and telecommunications equipment. The Company has proposed a 21-month budget of $2.6 million.

Recovery of Electric ISR Plan Capital Investment – Capital Placed in Service

The Company calculates the revenue requirement based on the projected capital amounts that will be placed into service plus associated Cost of Removal ("COR"). To develop the Plant in Service Target in this filing, the Company estimates the timing that capital spending goes into service. Each year, as part of the Company's annual reconciliation, the revenue requirement related to discretionary in-service amounts is trued-up based on the lesser of allowed discretionary capital spending or actual capital investment placed into service on a cumulative basis since the inception of the Electric ISR Plan. The discretionary categories include the Asset Condition, Non-Infrastructure, and System Capacity and Performance categories. Because of the multi-year nature of certain projects, the Plant in Service amount may include current and prior year(s) capital spending when a project is placed into service. Similarly, the capital spending portion of a project included in the current Plan may be placed into service in future fiscal periods and included in subsequent revenue requirement calculations during that project's in-service year.

Chart 18 below provides details regarding the proposed amounts for Capital Spending, Plant in Service, and Cost of Removal ("COR") that have been used to develop the 21-Month Electric ISR Plan revenue requirement.

Chart 18
21-Month Plan Proposed Capital Spending, Plant in Service, and COR
($000)

CY 2023 9 Mos. 4/1/23-12/31/23	Capital Spending	Plant in Service	COR	Capital Placed-in-Service + COR
Customer Request/Public Requirement	$20,683	$21,293	$1,976	$23,269
Damage Failure	11,651	12,078	1,841	13,919
Grid Modernization	33,877	5,660	930	6,590
Subtotal Non-Discretionary	66,211	39,031	4,747	43,778
Asset Condition	53,193	23,109	8,310	31,419
Non-Infrastructure	1,375	1,132	18	1,150
System Capacity & Performance	26,586	20,188	932	21,120
Subtotal Discretionary	81,154	44,429	9,260	53,689
Total	**$147,365**	**$83,460**	**$14,007**	**$97,467**

CY 2024 12 Mos. 1/1/24-12/31/24	Capital Spending	Plant in Service	COR	Capital Placed-in-Service + COR
Customer Request/Public Requirement	$28,357	$23,890	$2,207	$26,097
Damage Failure	15,878	17,808	1,965	19,773
Grid Modernization	47,983	55,039	1,292	56,331
Subtotal Non-Discretionary	92,218	96,737	5,463	102,200
Asset Condition	61,800	43,465	6,745	50,210
Non-Infrastructure	1,289	1,386	14	1,400
System Capacity & Performance	25,098	10,274	1,307	11,581
Subtotal Discretionary	88,187	55,125	8,066	63,191
Total	**$180,405**	**$151,862**	**$13,529**	**$165,391**

21-Month ISR Plan 4/1/23 - 12/31/24	**Capital Spending**	**Plant in Service**	**COR**	**Capital Placed-in-Service + COR**
Customer Request/Public Requirement	$49,040	$45,183	$4,183	$49,366
Damage Failure	27,529	29,886	3,806	33,692
Grid Modernization	81,860	60,699	2,222	62,921
Subtotal Non-Discretionary	158,429	135,768	10,210	145,978
Asset Condition	114,993	66,574	15,055	81,629
Non-Infrastructure	2,664	2,518	32	2,550
System Capacity & Performance	51,684	30,462	2,239	32,701
Subtotal Discretionary	169,341	99,554	17,326	116,880
Total	**$327,770**	**$235,322**	**$27,536**	**$262,858**

Attachment 1 – Capital Spending by Key Driver Category and Budget Classification

Spending Rationale and Budget Class	FY 2011 Actual	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Actual	FY 2022 Actual	NG FY 2023 (Dkt. 5209)	CY23 9 Mos. 4/1/23-12/31/23	CY24 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
3rd Party Attachments	$ (910)	$ 464	$ 223	$ 141	$ 271	$ 290	$ 160	$ 123	$ 400	$ 186	$ (629)	$ 103	$ 260	$ 210	$ 288	$ 498
Distributed Generation	-	-	(675)	195	981	(933)	3,760	280	1,815	1,568	7,615	9,801	1,000	750	1,000	1,750
Land and Land Rights	281	185	128	94	165	143	199	305	360	350	404	513	475	375	515	890
Meters	2,215	1,497	1,455	835	612	2,935	1,844	2,627	2,332	2,530	1,605	2,351	2,740	1,971	2,535	4,506
New Business - Commercial	4,287	3,391	3,722	4,957	4,781	7,568	7,815	5,625	7,293	8,702	7,158	8,325	8,950	6,820	9,366	16,186
New Business - Residential	3,530	2,833	2,886	3,593	3,769	5,085	4,598	4,618	4,337	5,186	2,536	4,691	7,060	5,409	7,428	12,837
Outdoor Lighting	411	495	488	758	479	129	144	185	455	667	509	617	560	431	592	1,023
Public Requirements	1,539	1,135	(1,231)	4,234	4,214	770	(124)	3,078	2,495	4,320	(1,407)	2,301	1,338	937	1,341	2,278
Transformers & Related Equip	3,278	3,075	3,415	2,331	2,488	1,425	1,837	2,786	4,503	5,157	4,199	5,631	4,800	3,780	5,292	9,072
Customer Requests/ Public Requirements	**14,631**	**13,075**	**10,410**	**17,138**	**17,760**	**17,412**	**20,233**	**19,627**	**23,989**	**28,667**	**21,990**	**34,335**	**27,183**	**20,683**	**28,357**	**49,040**
Damage/Failure	8,331	9,574	7,795	11,228	12,284	11,327	13,594	11,426	10,087	12,764	11,663	12,441	12,326	10,263	13,915	24,178
Major Storms	4,863	3,419	9,720	3,146	(9,240)	3,204	2,020	7,758	3,912	4,264	7,827	7,759	1,925	1,388	1,963	3,351
Damage/Failure	**13,194**	**12,993**	**17,515**	**14,374**	**3,044**	**14,531**	**15,614**	**19,184**	**13,999**	**17,028**	**19,491**	**20,200**	**14,251**	**11,651**	**15,878**	**27,529**
Grid Modernization	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**33,877**	**47,983**	**81,860**
Asset Condition	**5,831**	**10,320**	**8,070**	**20,905**	**25,140**	**27,179**	**31,274**	**41,980**	**32,896**	**32,878**	**41,816**	**35,792**	**48,289**	**53,193**	**61,800**	**114,993**
Non-Infrastructure	**706**	**267**	**2,269**	**(346)**	**1,217**	**457**	**622**	**362**	**673**	**145**	**(57)**	**1,100**	**1,520**	**1,375**	**1,289**	**2,664**
System Capacity & Performance	**10,795**	**13,955**	**11,249**	**25,972**	**25,890**	**19,920**	**16,371**	**25,905**	**39,515**	**24,958**	**17,387**	**15,303**	**13,508**	**26,586**	**25,098**	**51,684**
Grand Total	**$ 45,157**	**$ 50,610**	**$ 49,514**	**$ 78,043**	**$ 73,051**	**$ 79,499**	**$ 84,114**	**$107,058**	**$111,072**	**$103,676**	**$100,627**	**$106,730**	**$104,750**	**$147,365**	**$180,405**	**$327,770**

Attachment 2 – Project Detail for Capital Spending

Project #	Project Description	CY 2023 - 9 Months - 4/1/23 - 12/31/23	CY 2024 - 12 Months - 1/1/24 - 12/31/24
Customer Requests/Public Requirements			
COS0022	3RD PARTY ATTCH Blanket	210	288
VARIOUS	FROM DG FILE	750	1,000
COS0091	LAND AND LAND RIGHTS RI ELECT	375	515
C083649	RI LANDLINE METER REPLACEMENT	124	19
CN04904	NARR. METER PURCHASES	1,220	1,668
COS0004	METER BLANKET	627	848
C046977	RES FOR NEW BUS COMMERCIAL	2,395	3,289
COS0011	NEW BUS-COMM BLANKET	4,425	6,077
C046978	RESERVE FOR NEW BUS RES	309	424
COS0010	New Business - Res Blanket	5,100	7,004
COS0012	Streetlighting BLANKET	431	592
C086669	JO Pole Billing Project - RI	(1,350)	(1,800)
C046970	RESERVE FOR PUBLIC REQUIREMENTS UNI	1,387	1,905
COS0013	Public Requirements Blanket	900	1,236
CN04920	TRANSFORMER PURCHASES	3,780	5,292
Total Customer Requests/Public Requirements		20,683	28,357
Damage / Failure			
C087902	Westerly T2 Failure	231	-
C091379	Nasonville Substation Rebuild	1,092	1,637
COS0002	SUBSTATION BLANKET.	480	659
COS0014	Damage/Failure Blanket	7,725	10,609
C022433	STORM CAP CONFIRM PROGRAM PROJ	1,388	1,963
C046986	RES FOR D/F UNIDENTI	155	213
C051608	RES FOR D/F SUBSTATION	580	797
Total Damage / Failure		**11,651**	**15,878**
Grid Modernization			
EMRelayRe|	Electromechanical Relay Replacement Program	2,040	2,853
GMP-ADMS	GMP - ADMS/DERMS Advanced	105	140
GMP-AdvCa	GMP - Smart Capacitors & Regulators	4,635	6,261
GMP-AdvRe	GMP - Advanced Reclosers	17,405	25,264
GMP-DER M	GMP-DER Monitor/Manage	-	-
GMP-FiberN	GMP - Fiber Network	8,105	11,348
GMP-IT Infr	GMP - IT Infrastructure	1,514	2,019
GMP-Mobil	GMP-Mobile Dispatch	74	98
Total Grid Modernization		33,877	47,983
Non-Infrastructure			
COS0006	GENL EQUIP BLANKET	300	412
C040644	TELECOM SMALL CAPITAL WORK - RI	283	220
C086391	Verizon Copper to Fiber Conversions	792	657
Total Non-Infrastructure		1,375	1,289

Project #	Project Description	CY 2023 - 9 Months - 4/1/23 - 12/31/23	CY 2024 - 12 Months - 1/1/24 - 12/31/24
Asset Condition			
C087861	Apponaug Long Term Plan (D-Sub)	763	1,428
C087862	Apponaug Long-Term Plan (D-Line)	-	-
C087783	Centredale #50 Sub (D-Sub)	482	648
C087784	Centredale #50 Sub (D-Line)	634	1,102
C074427	Phillipsdale DSub	2,200	2,790
C087367	Phillipsdale DLine	190	161
C078801	Ph 1B - ProvStudy Admiral St Demolition	(257)	-
C078735	Ph 1B-PROVSTUDY NEW ADMIRAL ST 12KV D-SUB	1,850	4,272
C078797	Ph 1B-PROVSTUDY ADMIRAL ST-ROCHAMB D-SUB	750	-
C078802	Ph 1B-PROVSTUDY OLNEYVILLE 4KV D-LINE	720	-
C078803	Ph 1B-PROVSTUDY ADMIRAL ST 12KV MH&DUCT	10,037	6,200
C078804	Ph 1B-PROVSTUDY ADMIRAL ST 12KV CABLES	480	3,150
C078810	Ph 2 - ProvStudy HarrisAve 11kV(1129&1137)	200	214
C078811	Ph 2 - ProvStudy Geneva,Olnyvile,Rocham4kV	300	1,948
C078857	Ph 2-PROVSTUDY HARRIS AVE 4&11KV RETIRE	1,174	2,362
C078805	Ph 4-PROVSTUDY KNIGHTSVILLE 4KV CONVERT	8,016	4,566
C078806	Ph 4-PROVSTUDY KNIGHTSVILLE 4KV D-SUB	1,589	1,978
C055683	PAWTUCKET NO 1 (D-SUB)	66	-
TIV0001	Tiverton Sub (D-Sub)	85	341
C032019	BATTS/CHARGERS NE SOUTH OS RI	230	195
BSVS004	Central Falls #104 Sub (D-Line)	-	173
C026281	I&M - OS D-LINE OH WORK FROM INSP.	2,131	2,848
C080076	I&M - OS SUB-T OH WORK FROM INSP	125	113
COS0017	Asset Replacement Blanket	3,675	5,047
COS0026	Substation Asset Repl Blanket	240	330
C047829	IRURD HIGH HAWK	1,500	1,125
C049291	IRURD WOOD ESTATES PHASE 2	-	506
C049356	IRURD SILVER MAPLE PHASE 2	-	350
C050070	IRURD PLACEHOLDER RI	750	3,758
C050299	IRURD EASTWARD LOOK	1,454	-
C057882	IRURD CHATEAU APTS URD REHAB	-	128
C057903	IRURD WESTERN HILLS VILLAGE URD-	-	117
C057906	IRURD WOODVALE ESTATES URD-	-	117
C057921	IRURD-ROBIN HILLS ESTATES.	-	156
C058045	IRURD-TOCKWOTTON FARM_TF ROAD.	-	117
C084965	IRURD Sandy Point Farms Phase 2	579	-
C088337	EG Heights URD Cable Replacement	571	-
C088340	Paddock Estates URD Cable Replace	177	-
C088735	IRURD FAIR OAKS LN URD RI- LINCOLN	250	-
C088838	IRURD HIGH POINT & CIRCLE DR N.S.	250	-
C089226	IRURD Wethersfield Commons URD	750	-
C081006	FRANKLIN SQ BREAKER REPLACEMENT	437	-
C055392	RI UG CABLE REPL PROGRAM - SECONDAR	1,732	-
C078928	RI UG Cable Repl Program - Fdr 1164	282	-
C078921	RI UG Cable Repl Program - Fdr 1158	425	-
C087128	RI UG Cable Repl Prog Fdr 1103B	482	-
C087133	RI UG Cable Repl Prog Fdr 1121	273	-
C055343	RI UG Cable Placeholder	2,034	5,178

Project #	Project Description	CY 2023 - 9 Months - 4/1/23 - 12/31/23	CY 2024 - 12 Months - 1/1/24 - 12/31/24
Asset Condition (continued)			
BSVS002	Crossman St #111 Sub (D-Line)	183	514
BSVS010	Valley #102 & Farnum #105 Sub (D-Line)	675	225
C088052	Division St. 61F2 Reconductoring CRIW D Line	240	240
C088055	Hopkins Hill 63F6 Feeder TieCRIW D Line	150	150
C085405	Div St#61 T1 T2 Replacement CRIW	747	747
C088006	Anthony #64 Equipment Replacement CRIW	558	558
C088007	Natick #29 Equipment Replacement CRIW	181	181
C088008	Warwick Mall #28 Equipment Replacem CRIW	428	428
C088046	Coventry #54 Sub Relocation CRIW	488	488
C088047	Hope #15 Equipment Replacement CRIW	399	399
NWPT001	Dexter #36 Equipment Replacement	-	113
NWPT002	Gate II Equipment Replacement	-	105
NWPT003	Hospital #146 Equipment Replacement	-	603
NWPT004	Kingston #131 Equipment Replacement	-	1,891
NWPT005	Eldred 45J3 Reconfiguration	-	40
NWPT006	Dexter 36W44 Asset Replacement	-	128
NWPT008	CLX Cable Replacement	-	475
NWPT014	Merton #51 Equipment Replacement	-	919
NWRI003	West Greenville Airbreak Replacements	270	131
PROV001	Auburn Substation 4kV conversions common	-	795
PROV002	Auburn Substation 4kV conversions (115kV option)	-	508
PROV003	Elmwood 7F4 Rebuild Common	-	114
PROV004	Pontiac 27F2 Rebuild Common	-	102
PROV005	Lincoln Ave 72F6 Load Break	-	3
C089195	RI Repl ACNW Vault Vent Blowers	465	525
C087912	3763 Pole Replacements	783	-
Total Asset Condition		53,193	61,800

Project #	Project Description	CY 2023 - 9 Months - 4/1/23 - 12/31/23	CY 2024 - 12 Months - 1/1/24 - 12/31/24
System Capacity & Performance			
C058404	KINGSTON SUB IMPROVEMENTS (D-SUB)	1,038	-
C046726	EAST PROVIDENCE SUBSTATION (D-SUB)	750	2,580
C046727	EAST PROVIDENCE SUBSTATION (D-LINE)	483	1,869
C081675	NEW LAFAYETTE 115/12KV (D-SUB)	500	
C081683	NEW LAFAYETTE 115/12KV (D-LINE)	250	748
BSVS012	Staples #112 Reliability Improvements	270	640
C065166	WARREN SUB EXPANSION (D-SUB)	632	2,049
C065187	WARREN SUB EXPANSION (D-LINE)	1,337	1,327
SCW0003	Chase Hill Common Items		715
C085412	Weaver Hill Rd DSub	285	855
C088009	Weaver Hill Rd. SubT Extension	817	817
C085414	Weaver Hill Rd Feeder DLine	60	180
C087770	Nasonville #127 Sub (D-Sub)	1,875	3,563
C087771	Nasonville #127 Sub (D-Line)	37	41
TIV0002	Tiverton Sub (D-Line)	64	291
C091395	Recloser Installation Project_RI	9,504	-
C079494	PEACEDALE 3V0 D-SUB	15	-
C087362	Natick 3V0 D-SUB	405	135
C087362	Natick 3V0 D-SUB	405	135
C08TBD2	FY 2025 3V0 Work		675
COS0015	RELIABILITY BLANKET	1,580	2,170
COS0016	LOAD RELIEF BLANKET	225	309
COS0025	SUBSTATION LR/REL Blanket	187	258
C074428	EMS EXPANSION - WAMPANOAG 48	165	330
C074426	EMS EXPANSION - FRANKLIN SQ 11	438	77
C088048	Coventry 54F1 Reconductoring	675	675
C088057	Natick 29F1 Reconductoring	190	-
C088058	New London 150F6 Reconductoring	80	-
C088059	Kilvert 87F1 Line Extension	82	82
C088061	2232 Panto Rd. ERR	182	-
C088062	2232 Industrial Dr. ERR	163	-
EB00001	Bristol D Line	-	44
EB00002	Bristol D-Sub	-	19
NWPT007	Newport 203WS D Line	-	48
NWPT009	Jamestown Capacitor Bank	-	75
NWPT010	Eldred 45J4 D Line	-	49
NWPT011	Kingston D Line	-	47
NWPT012	Dexter 36W42 D Line	-	3
NWPT013	Newport 203W1 D Line	-	38
NWPT015	37K22 and 37K33 Reconfiguration	-	176
NWRI001	Farnum Pike 23F3 Reconductor	95	50
NWRI002	Putnam Pike 38F3 Reconductor	200	90
NWRI004	Smart Capacitor Installations	165	85
NWRI005	West Greenville 45F2 Line Regulator	60	31
NWRI006	Chopmist 34F2 Line Regulator	60	31
NWRI007	Chopmist 34F3 Stepdown Conversion	646	420
SCW0001	Kenyon Common Items	60	184
SCW0002	Kenyon 68FS Extension	176	489
CEMI4001	CEMI 4 Program	820	1,640
C005505	IE - OS DIST TRANSFORMER UPGRADES	1,094	958
C013967	PS&I ACTIVITY - RHODE ISLAND	75	100
C091057	Lafayette 30F4 - Narrow Ln 3-Phase	441	-
Total System Capacity & Performance		26,586	25,098

Attachment 3 – Five-Year Budget with Details

		Docket 5209			5 Year Investment Plan					Major Project - Details						
Spending Rationale and Category	ISR Grouping	FYTD Actuals 9/30/22	FY23 Q2 Forecast	FY23 Budget	CY23 Forecast (9 mos)	CY24 Forecast (12 mos)	CY25 Forecast	CY26 Forecast	CY27 Forecast	Major Project - Current Phase	Total Current Sanction	Initial Estimate	Date of Last Sanction	Est. Constr Start	Est. Const End	PY Capital Spending
Customer Request/Public Requirement																
	3rd Party Attachments	737	860	260	210	288	297	306	315							
	Land and Land Rights	188	434	475	375	515	530	546	562							
	Distributed Generation	6,860	1,715	1,000	750	1,000	1,000	1,000	1,000							
	Meters	1,017	2,704	2,740	1,971	2,535	2,586	2,629	2,691							
	New Business - Commercial	5,261	10,034	8,950	6,820	9,366	9,647	9,937	10,235							
	New Business - Residential	3,716	7,150	7,060	5,409	7,428	7,651	7,880	8,117							
	Outdoor Lighting	208	482	560	431	592	610	628	647							
	Public Requirements	468	1,268	1,338	937	1,341	1,435	1,532	1,632							
	Regulatory Requirement	121	121	-	-	-	-	-	-							
	Transformers	2,398	4,836	4,800	3,780	5,292	5,557	5,834	6,126							
Total Customer Request/Public Requirement		**20,974**	**29,605**	**27,183**	**20,683**	**28,357**	**29,312**	**30,292**	**31,324**							
Damage Failure																
	Damage /Failure	6,903	12,187	12,326	9,171	12,278	12,646	13,026	13,417							
	Storms	1,545	2,232	1,925	1,388	1,963	2,075	2,175	2,275							
	Nasonville Substation Rebuild	425	1,973	-	1,092	1,637	223	-	-							
Total Damage Failure		**8,873**	**16,392**	**14,251**	**11,651**	**15,878**	**14,944**	**15,201**	**15,692**							
Grid Modernization Plan																
	ADMS/DERMS Advanced	-	-	-	105	140	3,160	1,569	4,387							
	Advanced Reclosers	-	-	-	17,405	25,264	25,845	26,440	27,048							
	DER Monitor/Manage	-	-	-	-	-	-	2,288	4,044							
	Electromechanical Relay Repl Pgm	-	-	-	2,040	2,853	5,053	8,564	6,735							
	Fiber Network	-	-	-	8,105	11,348	17,875	15,278	7,997							
	IT Infrastructure	-	-	-	1,514	2,019	2,999	4,282	4,837							
	Mobile Dispatch	-	-	-	74	98	172	196	196							
	Smart Capacitors & Regulators	-	-	-	4,635	6,261	6,075	6,215	6,299							
Total Grid Moderization		-	-	-	33,877	47,983	61,179	64,831	61,542							
Total Non-Discretionary		**29,847**	**45,997**	**41,433**	**66,211**	**92,218**	**105,435**	**110,323**	**108,558**							

Attachment 3 – Five-Year Budget with Details

Spending Rationale and Category	ISR Grouping	Docket 5209			5 Year Investment Plan					Major Project - Details						
		FYTD Actuals 9/30/22	FY23 Q2 Forecast	FY23 Budget	CY23 Forecast (9 mos)	CY24 Forecast (12 mos)	CY25 Forecast	CY26 Forecast	CY27 Forecast	Major Project - Current Phase	Total Current Sanction	Initial Estimate	Date of Last Sanction	Est. Constr Start	Est. Const End	PY Capital Spending
Asset Condition																
Major Projects	Apponaug Substation	-	254	-	763	1,428	1,096	255	16	Asset Planning	-	-	-	-	-	-
	Centredale Substation	-	-	-	1,116	1,750	2,543	1,302	540	Asset Planning	-	-	-	-	-	-
	Dyer St substation	6,017	10,148	3,500	-	-	-	-	-	Construction	21,730	14,154	Apr-21	Sep-21	Mar-23	10,378
	Phillipsdale Substation	-	-	-	2,390	2,951	4,201	4,440	2,090	Development	-	-	-	Aug-23	Feb-26	-
	ProvStudy Phase 1A	896	1,501	1,484	-	-	-	-	-	Construction	11,432	11,482	Jan-20	Oct-20	Nov-23	6,959
	ProvStudy Phase 1B	1,702	9,029	16,585	13,580	13,622	3,600	1,505	-	Construction	55,695	55,695	Aug-21	Feb-22	Apr-25	4,049
	ProvStudy Phase 2	8	158	300	1,674	4,524	9,010	7,798	1,766	Development	-	-	-	May-23	Jun-27	251
	ProvStudy Phase 3	-	-	-	-	-	-	-	-	Development	-	-	-	-	-	-
	ProvStudy Phase 4	437	1,817	1,217	9,605	6,544	2,564	128	-	Development	-	-	-	May-23	Mar-25	438
	Southeast substation	707	663	223	66	-	-	-	-	Construction	25,440	18,600	Jun-19	Oct-19	Aug-23	22,863
	Tiverton Substation	-	-	-	85	341	688	786	491	Development	-	-	-	-	-	-
Other	Batteries	2	130	130	230	195	155	300	75							
	BSVS 4kV Substation Ret.	-	-	-	-	173	578	1,215	1,677							
	Blanket	2,388	4,988	5,160	3,915	5,377	5,538	5,704	5,876							
	Other	669	3,222	5,464	1,220	-	-	-	-							
	Other Area Study Projects - BSVS	-	-	-	858	739	557	488	116							
	Other Area Study Projects - CRIW - D-Line	-	-	-	390	390	618	650	455							
	Other Area Study Projects - CRIW Equip Re	-	-	-	2,801	2,801	4,433	4,666	3,267							
	Other Area Study Projects - East Bay	-	-	-	-	-	19	6	-							
	Other Area Study Projects - Newport	-	-	-	-	4,274	7,424	9,104	8,847							
	Other Area Study Projects - NWRI	-	-	-	270	131	-	-	-							
	Other Area Study Projects - Providence	-	-	-	-	1,522	3,552	6,420	6,522							
	Other Area Study Projects - SCW	-	-	-	-	-	-	-	772							
	Reserve	-	-	-	-	-	1,000	1,000	1,000							
	RI.I&M	127	713	3,000	2,256	2,961	3,000	3,000	3,000							
	RI.UG Cable Replacement	2,025	4,747	5,700	5,228	5,178	6,000	6,000	6,000							
	RI.URD	4,182	6,488	5,000	6,281	6,374	6,575	6,675	6,775							
	UG Improvements	669	792	525	465	525	700	175	-							
Total Asset Condition		**19,829**	**44,651**	**48,289**	**53,193**	**61,800**	**63,848**	**61,616**	**49,284**							

Attachment 3 – Five-Year Budget with Details

		Docket 5209			5 Year Investment Plan					Major Project - Details						
Spending Rationale and Category	ISR Grouping	FYTD Actuals 9/30/22	FY23 Q2 Forecast	FY23 Budget	CY23 Forecast (9 mos)	CY24 Forecast (12 mos)	CY25 Forecast	CY26 Forecast	CY27 Forecast	Major Project - Current Phase	Total Current Sanction	Initial Estimate	Date of Last Sanction	Est. Constr Start	Est. Const End	PY Capital Spending
Non-Infrastructure																
Other	Blanket	(797)	418	520	583	632	725	513	450							
	Other	-	-	-	-	-	-	-	-							
	Verizon Copper to Fiber	47	481	1,000	792	657	941	241	-							
Total Non-Infrastructure		**(750)**	**898**	**1,520**	**1,375**	**1,289**	**1,666**	**753**	**450**							
System Capacity & Performance																
Major Projects	Aquidneck Island	415	847	730	1,038	-	-	-	-	Development	4,000	4,000	Jul-20	Feb-23	May-23	848
	Chase Hill - Second Half of Station	-	-	-	-	-	755	1,761	1,258	Asset Planning	-	-	-	-	-	-
	Chase Hill Common Items	-	-	-	-	715	1,668	1,906	477	Asset Planning	-	-	-	-	-	-
	East Providence Substation	227	2,383	2,495	1,233	4,449	4,664	3,474	820	Development	16,000	16,000	Feb-17	Apr-24	Oct-26	1,303
	Mainline Recloser Enhancements	-	990	-	9,504	-	-	-	-	Development	-	7,900	-	-	-	-
	Nasonville Substation	-	-	-	1,912	3,604	1,894	615	34	Asset Planning	-	-	-	-	-	-
	New Lafayette Substation	781	1,291	2,914	750	748	5,344	151	-	Development	13,300	13,300	Oct-20	Apr-25	Nov-27	3,242
	Staples Substation Reliability Imprvmnts	-	-	-	270	640	681	851	227	Asset Planning	-	-	-	-	-	-
	Tiverton Substation	-	-	-	64	291	574	656	410	Asset Planning	-	-	-	-	-	-
	Warren Substation	153	1,555	1,824	1,969	3,376	2,366	747	111	Development	8,700	8,700	Feb-17	Apr-23	May-27	781
	Weaver Hill Rd substation	-	-	-	1,162	1,852	2,387	2,512	1,758	Asset Planning	-	-	-	-	-	-
Other	3V0	224	822	740	825	945	225	-	-							
	Blanket	1,491	3,128	2,030	1,992	2,737	2,819	2,905	2,991							
	EMS/RTU	1,225	1,399	1,165	603	407	1,647	510	-							
	Other	1,152	2,731	1,600	1,610	1,058	1,600	1,600	1,600							
	Other Area Study Projects - CRIW	-	-	-	1,372	757	1,198	1,261	883							
	Other Area Study Projects - East Bay	-	-	-	-	63	305	378	95							
	Other Area Study Projects - Newport	-	-	-	-	436	482	112	-							
	Other Area Study Projects - NWRI	-	-	-	1,226	707	-	-	-							
	Other Area Study Projects - SCW	-	-	-	236	673	1,263	1,863	2,434							
	Reserve	-	-	-	-	-	1,000	1,000	1,000							
	CEMI-4	-	-	-	820	1,640	1,640	1,640	1,640							
	VVO	354	914	9	-	-	-	-	-							
Total System Capacity & Performance		**6,022**	**16,060**	**13,507**	**26,586**	**25,098**	**32,510**	**23,942**	**15,737**							
Total Discretionary		**25,101**	**61,610**	**63,316**	**81,154**	**88,187**	**98,024**	**86,311**	**65,471**							
Total Capital Spending		**54,948**	**107,607**	**104,750**	**147,365**	**180,405**	**203,458**	**196,634**	**174,029**							

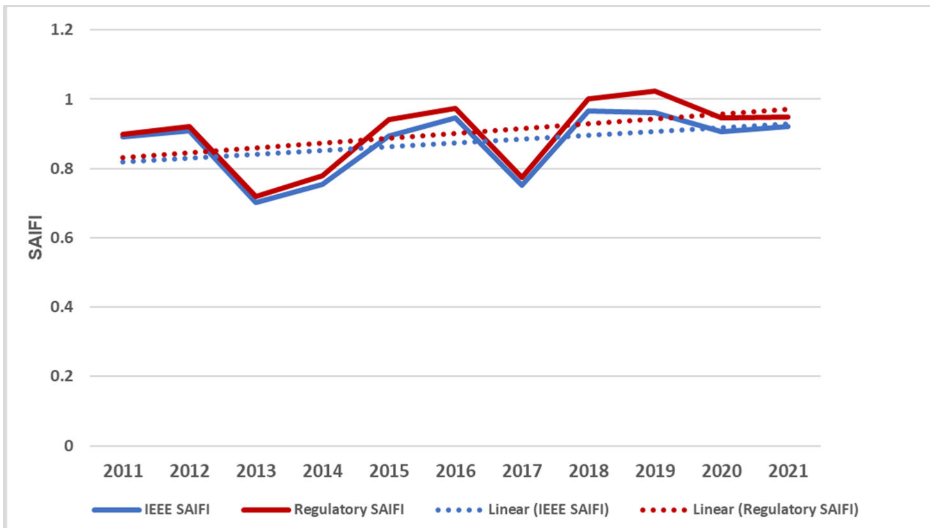
Attachment 4 – System Reliability Data

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance metrics in calendar year ("CY") 2021, with SAIFI of 0.949 against a regulatory target of 1.05, and SAIDI of 68.8 minutes, against a regulatory target of 71.9 minutes. Trees, Intentional, Deteriorated Equipment and Human Element/Other were the top four drivers affecting customers, accounting for 63 percent of all interruptions in CY 2021.

The Company recognizes that Regulatory targets for both SAIFI and SAIDI were developed over 20 years ago and customer expectations have changed since then. With the expected widespread adoption of clean energy technologies like EVs and electric heating, the availability of electricity becomes increasingly more important. To further investigate the Company's performance, an effort to review metrics against IEEE SAIDI and SAIFI benchmarks in addition to Regulatory targets was conducted.

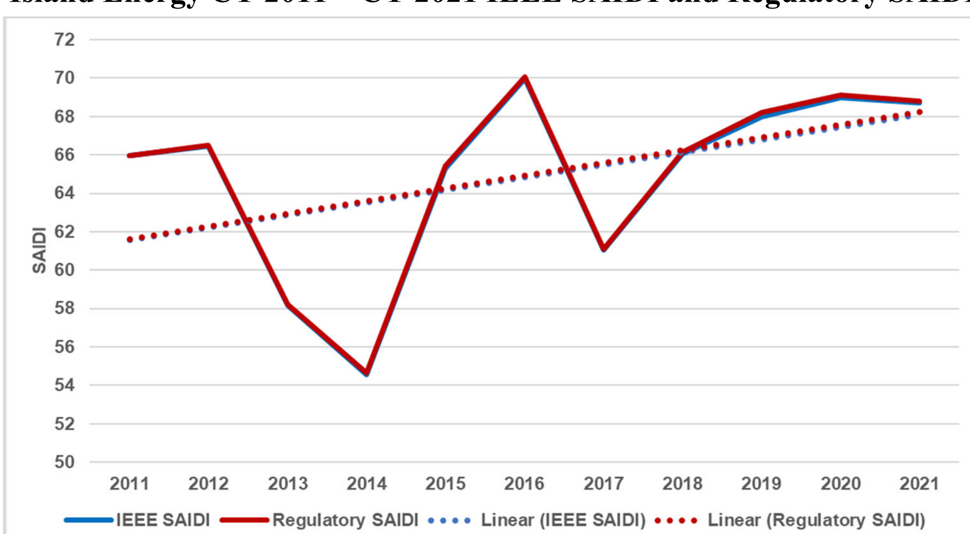
Attachment 4 – Chart 1

Rhode Island Energy CY 2011 – CY 2021 IEEE SAIFI and Regulatory SAIFI



Attachment 4 – Chart 2

Rhode Island Energy CY 2011 – CY 2021 IEEE SAIDI and Regulatory SAIDI



The analysis from CY 2012 to CY 2021, indicates RIE has been experiencing an uptrend for both SAIFI and SAIDI.

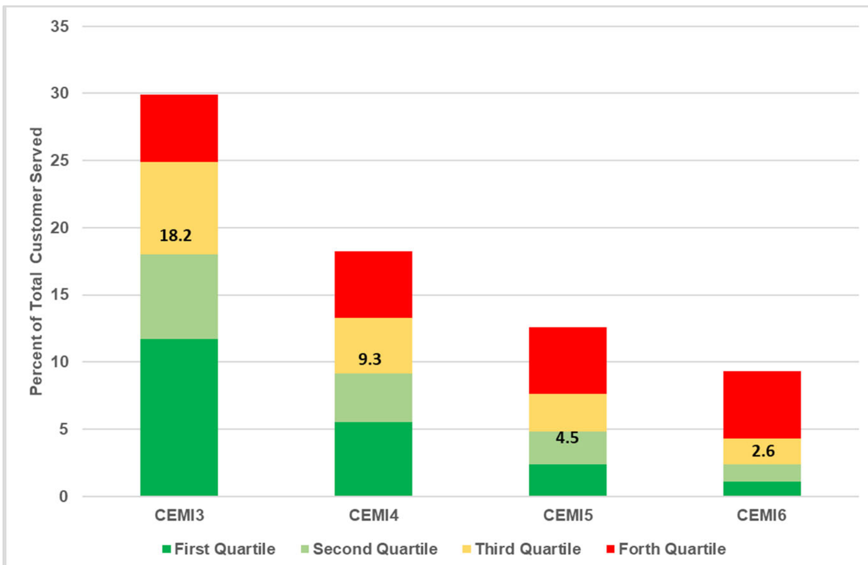
In addition to reviewing SAIFI and SAIDI performance metrics the Company used the 2022 JD Power Electric Utility Residential Customer Satisfaction Study to benchmark itself against similar regional utilities. Results indicate that the Company falls in the 4th Quartile for overall satisfaction and specifically Power Quality and Reliability. It is therefore critical that the Company continue to invest in its infrastructure and vegetation management programs not only to meet performance targets but to exceed them year over year to provide reliable electric delivery service and improve customer satisfaction.

In addition to reviewing system wide metrics, the Company will also increase focus on areas of a system, with minimal customers, that have experienced poor performance. While the Company does perform Engineering Reliability Reviews ("ERRs") on an annual basis, circuits are selected to be analyzed by reliability metrics which are not heavily impacted by localized issues. To address these areas of poor performance the Company is using a CEMI 4 ("Customers Experiencing Multiple Interruptions") index to identify those portions of the system that have experienced reliability challenges. CEMI measures customers who are experiencing the worst reliability in a localized area which may be masked by an acceptable overall system average. CEMI 4 index is aligned with PPL's other CEMI programs.

The chart below shows the Company's performance of CEMI compared to the 2021 EEI performance metrics:

Attachment 4 – Chart 3

RIE CEMI Performance VS EEI Survey 2021



The chart indicates that the Company falls in the third quartile for all but CEMI-5 which is borderline between the second and third quartiles. The Company's goal is to rank in the first quartile within five to ten years. This will be achieved by using the CEMI-4 index to implement a targeted set of electric reliability improvement projects to reduce the number of interruptions customers experience in areas of poor performance areas. Three-year quarterly-based CEMI data will be used to prioritize customers that have experienced the most interruptions. The proposed spending for this program has been added to the Plan.

Annual Reliability Performance

The Company's annual service quality targets are measured by excluding major event days. A Major Event Day ("MED") is defined as a day on which the daily system SAIDI exceeds a MED threshold value. The MED threshold value for CY 2021 was 6.67 minutes. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.[7] The Plan focuses on the underlying drivers of reliability during the entire year. Including major event days would skew that analysis significantly for the small number of days a year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually weather driven events. In CY 2021, four days were characterized as major event days. Attachment 4, Chart 4 below provides historical storm details and lists the major event days in CY 2021.

[7] For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began.

Attachment 4 - Chart 4

Historical Storm Data

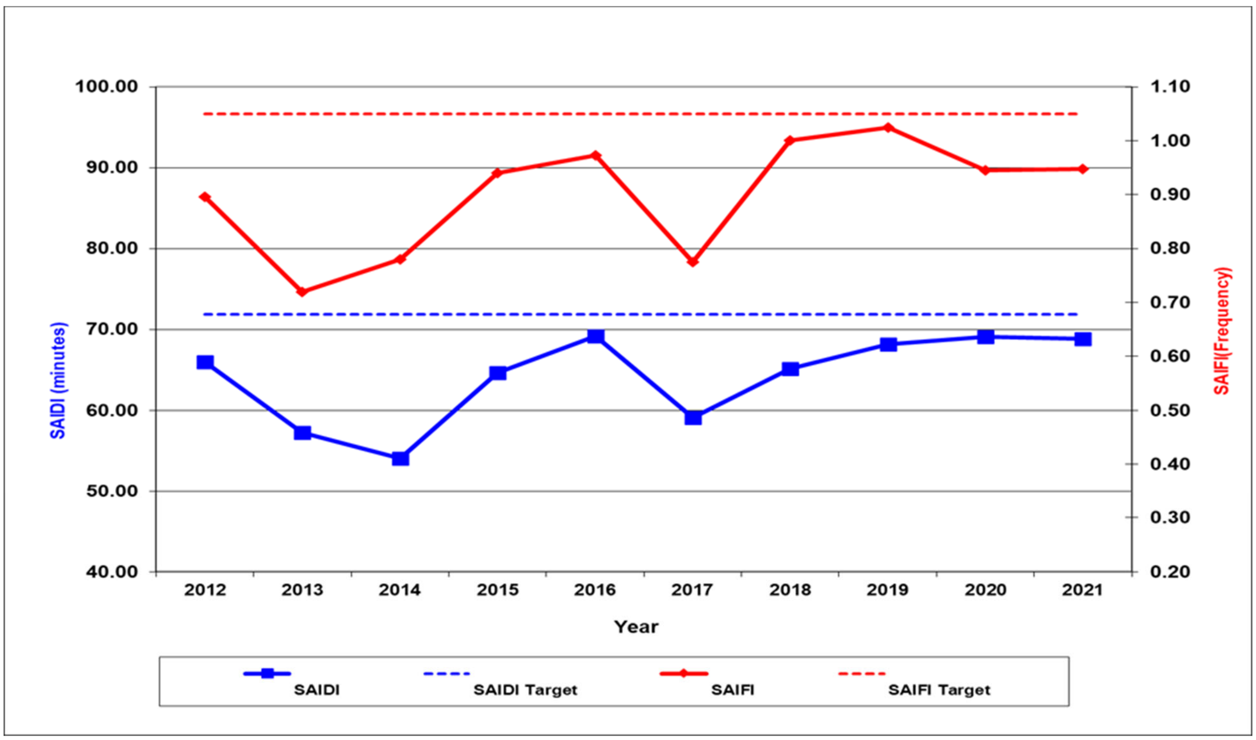
	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	CY21
SAIFI - Target 1.05	0.90	0.72	0.78	0.94	0.97	0.78	1.00	1.02	0.95	0.95
SAIDI - Target 71.9	66.00	57.30	54.06	64.30	69.13	59.10	65.11	68.20	69.11	68.80
# of Major Event Days	4	3	0	1	4	4	6	6	6	4
Total Customers Interrupted on major event days	201,709	268,925	7,287	141,046	114,772	203,211	282,481	177,296	352,939	240,195

CY 2021 Major Event Days

CY 2021 Major Event Days	Days Excluded	Total Customers Interrupted	Daily SAIDI
March 2, 2021 Storm	3/2/2021	16,435	8.42
August 22, 2021 Storm Henri	8/22/2021	94,730	211.77
October 27, 2021 Storm	10/27/2021	113,718	151.78
November 1, 2021 Storm	11/13/2021	15,312	8.40

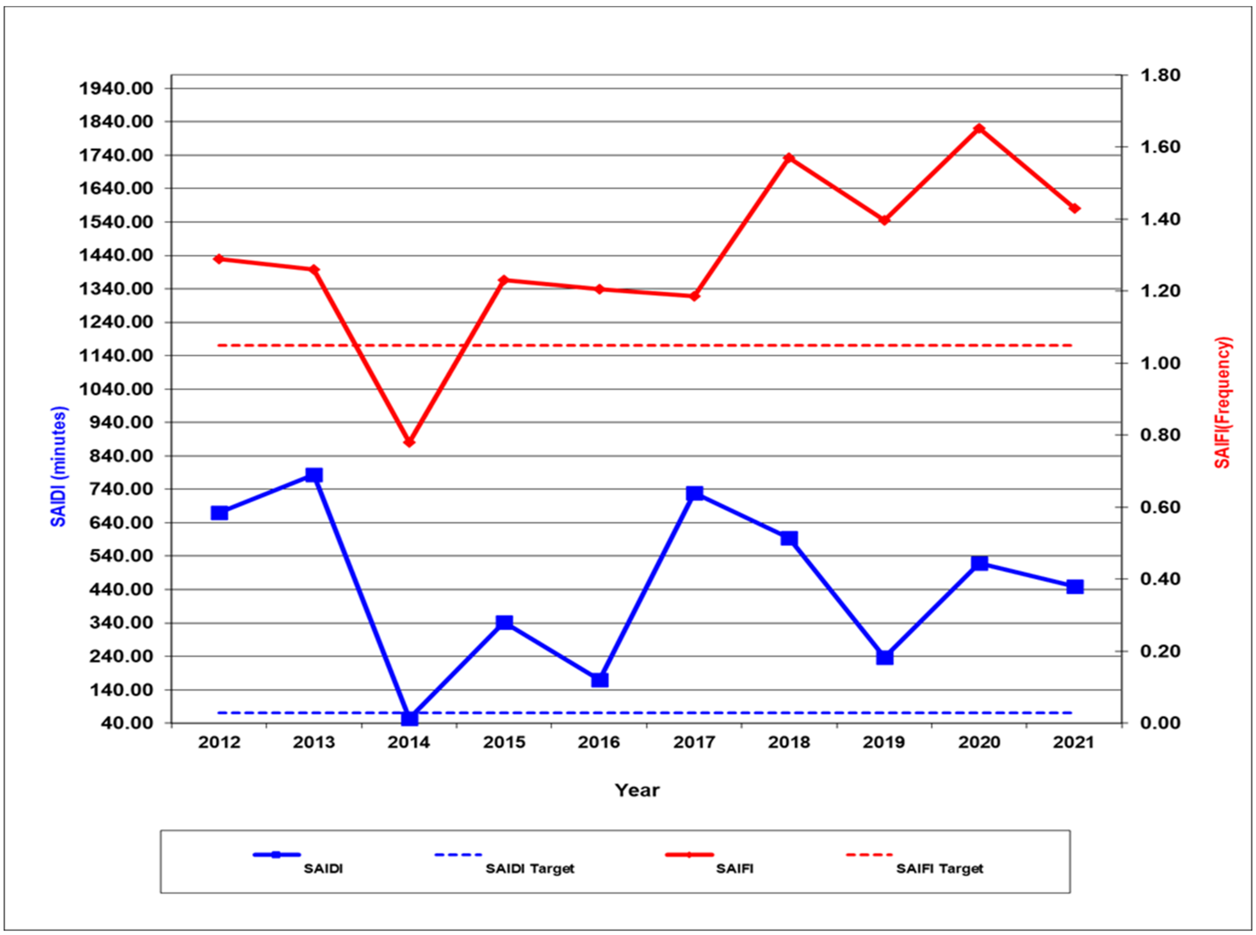
A comparison of reliability performance in CY 2021 to previous years is shown in Attachment 4, Chart 5 below.

Attachment 4 - Chart 5
RI Reliability Performance CY 2012 – CY 2021
Regulatory Criteria (Excluding Major Event Days)



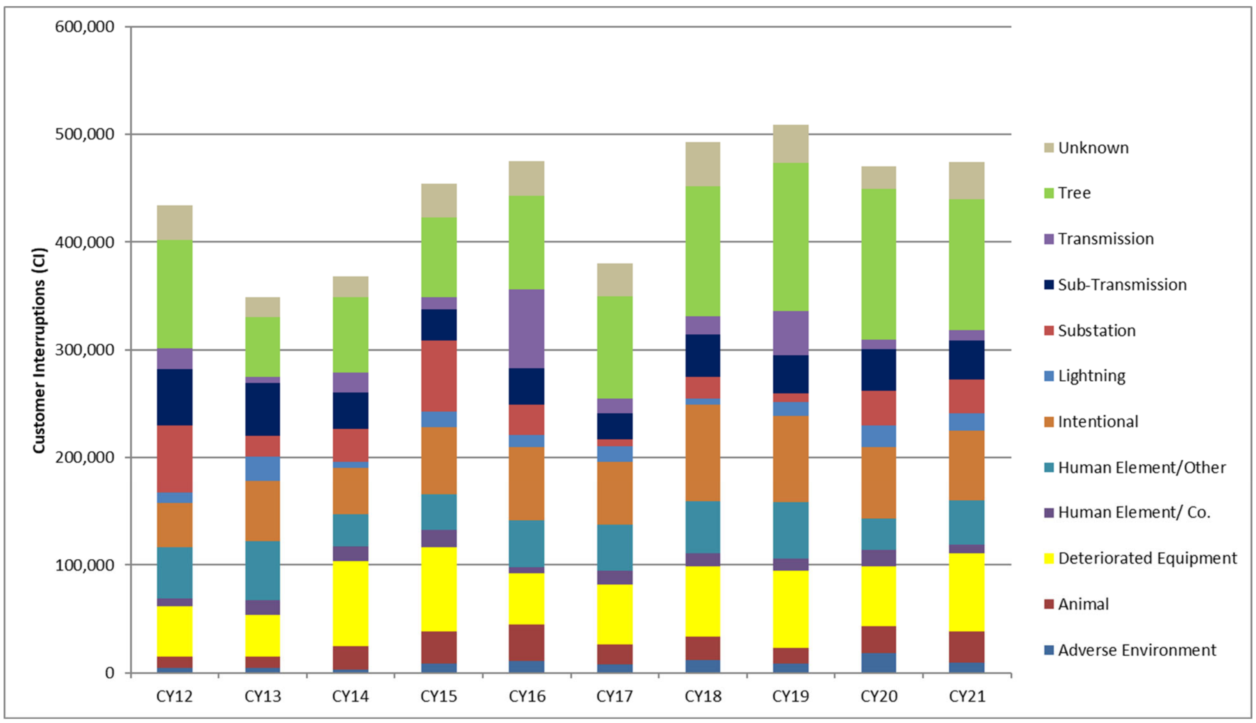
For informational purposes, Attachment 4, Chart 6 below shows reliability performance from CY 2012 to CY 2021, including major event days.

Attachment 4 - Chart 6
RI Reliability Performance CY 2012 – CY 2021
Regulatory Criteria (Including Major Event Days)



Attachment 4, Chart 7 below shows customers interrupted by cause for CY 2012 through CY 2021. Attachment 4, Chart 5 shows the same information in tabular form.

Attachment 4 - Chart 7
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2012-2021)



Attachment 4 - Chart 8
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2012-2021)

Cause	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	CY21
Adverse Environment	4,778	4,318	3,220	8,677	10,928	8,115	11,964	8,507	17,973	9,212
Animal	9,912	10,324	21,247	29,831	33,541	18,340	21,664	14,277	25,405	28,874
Deteriorated Equipment	47,301	39,131	79,260	77,575	47,966	55,316	65,386	72,114	55,603	72,996
Human Element/ Co.	7,043	13,481	13,259	16,619	5,489	12,995	11,462	11,392	15,066	7,801
Human Element/Other	47,404	54,719	29,908	33,049	43,514	42,510	48,520	52,266	29,164	40,853
Intentional	40,927	55,927	43,132	62,373	68,273	58,544	90,092	80,218	66,301	65,392
Lightning	9,362	23,310	5,745	14,374	10,832	14,505	5,766	12,648	20,127	15,801
Substation	63,397	18,882	30,888	65,932	28,525	6,616	19,802	7,830	32,413	31,896
Sub-Transmission	51,972	48,902	33,556	29,211	33,994	23,710	39,235	35,645	38,474	36,182
Transmission	19,099	5,958	18,284	11,594	72,808	13,786	17,106	40,969	8,856	9,232
Tree	100,459	55,056	70,277	73,248	87,036	95,025	120,812	137,437	140,002	121,540
Unknown	32,176	19,008	19,657	31,703	32,088	30,918	41,014	35,586	21,341	34,354
Grand Total	**433,830**	**349,016**	**368,433**	**454,186**	**474,994**	**380,380**	**492,823**	**508,889**	**470,725**	**474,133**

Trees, Deteriorated Equipment, and Intentional were the top three drivers affecting customers, accounting for 55 percent of all interruptions in CY 2021. It is, therefore, critical that the Company continue to invest in its infrastructure and vegetation management programs to provide reliable electric delivery service to customers.

Attachment 5 – Docket 4600 Analysis

Attachment 5-1 – CEMI-4 Program

Attachment 5-2 – Mainline Recloser Enhancement Program

Attachment 5-3 – Nasonville Substation

Attachment 5-4 – Weaver Hill Substation Project

FY2024 New Project
Attachment 5-1 CEMI 4 Program

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	The Company's CEMI 4 program will provide targeted reliability benefits to customers experiencing significantly poorer performance than system averages.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances	A more reliable grid can attract new business resulting in job creation.
Address the challenge of climate change and other forms of pollution	Neutral	This reliability project does not impact climate change.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This reliability project does not change system characteristics that would facilitate customer investments.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	This project does not change the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral	This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives.

Docket 4600 Benefit-Cost Framework

Project Name:	CEMI 4 Program
Area Study:	None

Problem: Current reliability metrics such as System and Circuit Average Interruption Frequency Indices measure the experience of the average customer; however, using them exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This leads to uneven reliability performance across the distribution circuits and unhappy customers. Currently, approximately 12% (60,000) of Rhode Island Energy customers experience four or more interruptions in a rolling twelve-month period, putting Rhode Island Energy in the third quartile of performance.

Preferred Plan: The CEMI 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.

Alternate Plan: None

Summary of Benefit - Cost Analysis

Preferred Plan	
Benefit Cost Ratio	1.05
Net Benefit/Cost	$ 675,000.00

Alternate Plan	
Benefit Cost Ratio	
Net Benefit/Cost	$ -

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20-year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.
5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (12,640,000)	Distribution program costs (C, R, OM) and yearly expense to operate and maintain the program equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the program equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ -	This program does not have associated transmission program costs.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this program.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This program does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This program does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This program does not result in any line loss savings or energy savings.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This program does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	$ -	This program does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This program does not result in any line loss savings or capacity savings.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ -	This program does not impact generation capacity or impact REC costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This program does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This program does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This program does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This program is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This program does not impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This program does not result in energy savings that impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This program does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This program does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This program does not impact distribution system safety.
Benefit	Power System	Distribution system performance	$ -	There are no distribution system performance benefits from this program aside from the reliability benefits quantified below.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Utility low income	$ -	This program does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ 13,315,000	Reliability benefits were calculated using the USDOE ICE Calculator for this program. The program is estimated to provide an approximate customer benefit of $1.4M per year with a 20-year net present value benefit of approximately $13M.
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this program.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This program does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This program does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This program does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This program does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	GHG savings are associated with loss reductions from this program and avoided bulk energy purchases.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	Criteria air pollutant and other environmental externalist costs are associated with loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	Conservation and community benefits	$ -	This program does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This program does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This program does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This program does not impact low income participant non-energy benefits.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Societal	Public Health	$ -	Public Health benefits are associated with emissions reductions through loss reductions from this program and avoided bulk energy purchases.
Benefit	Societal	National Security and US international influence	$ -	This program does not impact National Security.

Attachment 5-2 Mainline Recloser Enhancement Project

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	The Company's Mainline Recloser Enhancement project will provide substantial reliability benefits.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances	A more reliable grid can attract new business resulting in job creation.
Address the challenge of climate change and other forms of pollution	Neutral	This reliability project does not impact climate change.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This reliability project does not change system characteristics that would facilitate customer investments.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	This project does not change the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral	This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives.

Docket 4600 Benefit-Cost Framework

Project Name: Mainline Recloser Enhancements

Area Study: None

Problem: There are approximately 100 4kV and 15 kV circuits that have zero reclosers serving greater than one mile of overhead line exposure and more than 100 customers. In addition, there are approximately 70 15kV circuits that have only one recloser serving greater than five miles of overhead line exposure and more than 1,000 customers. The absence of reclosers on these circuits increases the amount of customer outages due to the lack of sectionalization and reduces the ability to remotely transfer load during an outage. The Company has determined that the lack of reclosers is a contributing factor to the rising System Average Interruption Frequency Index ("SAIFI") values.

Preferred Plan: Install reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts. This effort will consider future feeder rearrangements proposed by area study recommendations to ensure recloser reliability value. All reclosers will use the latest control technology aligned with the pending Grid Modernization Plan ("GMP") and location selection will be aligned with ultimate GMP implementation.

Alternate Plan: None

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio 2.33

Net Benefit/Cost $ 22,955,000.00

Alternate Plan

Benefit Cost Ratio

Net Benefit/Cost $ -

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20-year period net present value, with the cost calculations taking into consideration revenue requirements.
2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.
3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.
4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.
5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (17,223,000)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ -	This project does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This project does not result in any line loss savings or energy savings.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This project does not result in any line loss savings or capacity savings.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This project does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ -	This project does not impact generation capacity or impact REC costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This project does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This project does not impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This project does not result in energy savings that impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This project does not impact distribution system safety.
Benefit	Power System	Distribution system performance	$ -	There are no distribution system performance benefits from this project aside from the reliability benefits quantified below.
Benefit	Power System	Utility low income	$ -	This project does not impact low income participant non-energy benefits.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ 40,178,000	Reliability benefits were calculated using the USDOE ICE Calculator for this project. The project is estimated to provide an approximate customer benefit of $3M per year with a 20-year net present value benefit of approximately $40M.
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	GHG savings are associated with loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	Criteria air pollutant and other environmental externalist costs are associated with loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	Conservation and community benefits	$ -	This project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	$ -	Public Health benefits are associated with emissions reductions through loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	National Security and US international influence	$ -	This project does not impact National Security.

Attachment 5-3 – Nasonville Substation

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	This project will provide substantial contingency benefits.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Neutral	This project does not impact the Rhode Island economy.
Address the challenge of climate change and other forms of pollution	Neutral	This project does not directly impact climate change but increases the localized system's hosting capacity. The increased hosting capacity could be used by renewable generation which would help address the challenges of climate change.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This project does not directly facilitate customer investments but increases the localized system's hosting capacity. The increased hosting capacity could reduce interconnection costs for customers.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	This project does not change the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral	This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives.

Docket 4600 Benefit-Cost Framework

Project Name: Nasonville Substation - Feeders 127W40, 127W41, 127W42 & 127W43

Area Study: Northwest Rhode Island

Problem: Nasonville is a single transformer 115/13.8kV substation that consists of four feeders. It is currently very difficult to offload the feeders due to minimal ties to feeders other than Nasonville. The 127W43 feeder is predicted to exceed the summer normal rating as well as load-at-risk criteria. Contingency loss of the Nasonville T1 transformer exceeds load-at-risk criteria and could result in approximately 13MVA (350 MWHr) of unserved load.

Preferred Plan: The recommended plan for the Nasonville Substation includes bringing a new 115kV OH supply line from Woonsocket substation to Nasonville substation and adding a second transformer and straight bus to the existing Nasonville substation. This option requires installation of a new 115kV radial line with two breaker bays at Woonsocket substation in order to bring a new 115kV line through the existing ROW which is about 6 miles long (new 115kV source). This plan also recommends replacing the existing 115kV protection on the existing Transformer (T1) with a circuit switcher at the Nasonville substation.

Alternate Plan: This option recommends installing a new 115kV bay at West Farnum substation to bring a new 115 kV overhead supply line to Nasonville substation. A second transformer and straight bus will also be added to the Nasonville substation similar to the recommended plan.

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio	0.00
Net Benefit/Cost	$ (68,752,751.35)

Alternate Plan

Benefit Cost Ratio	0.00
Net Benefit/Cost	$ (72,754,971.06)

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.
2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.
3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.
4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.
5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (19,695,565.35)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ (49,057,186.00)	Transmission project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This project does not directly affect energy usage but does increase the system's hosting capacity for distributed generation. The distributed generation enabled by this project could then affect energy pricing.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This project does not impact generation capacity or impact REC costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Retail Supplier Risk Premium	$ -	This project does not impact retail supplier risk premium.
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This project does not impact capacity costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This project does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ -	This project increases the localized system's transmission and substation hosting capacity for distributed generation, which could reduce third party interconnection costs. However, this project does not add distribution line hosting capacity.
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This project does not impact transmission capacity costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This project does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This project is not categorized as an investment under uncertainty.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This project does not directly impact DRIPE, but the distributed generation enabled by this project could impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This project does not directly impact greenhouse gas compliance costs, but the renewable generation enabled by this project could impact greenhouse gas compliance costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This project provides improved worker safety features at the Nasonville substation.
Benefit	Power System	Distribution system performance	$ -	This project will provide for new transformer and feeder loading and voltage monitoring and control equipment that will be used to improve the performance of the localized area.
Benefit	Power System	Utility low income	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ -	The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure support specific areas in which system resiliency/hardening is a focus. This specific project is to address contingency load at risk which is a component of resiliency.
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.

Benefit/Cost	**Level**	**Mixed Cost-Benefit, Cost, or Benefit Category**	**Quantitative Assessment NPV (2023)**	**Qualitative Assessment:**
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Conservation and community benefits	$ -	This project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	$ -	This project does not directly impact Public Health
Benefit	Societal	National Security and US international influence	$ -	This project does not impact National Security.

Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (19,695,565.35)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ (53,059,405.71)	Transmission project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This project does not directly affect energy usage but does increase the system's hosting capacity for distributed generation. The distributed generation enabled by this project could then affect energy pricing.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	$ -	This project does not impact retail supplier risk premium.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This project does not impact capacity costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This project does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ -	This project increases the localized system's transmission and substation hosting capacity for distributed generation, which could reduce third party interconnection costs. However, this project does not add distribution line hosting capacity.
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This project does not impact transmission capacity costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This project does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This project does not directly impact DRIPE, but the distributed generation enabled by this project could impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This project does not directly impact greenhouse gas compliance costs, but the renewable generation enabled by this project could impact greenhouse gas compliance costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This project provides improved worker safety features at the Nasonville substation.
Benefit	Power System	Distribution system performance	$ -	This project will provide for new transformer and feeder loading and voltage monitoring and control equipment that will be used to improve the performance of the localized area.
Benefit	Power System	Utility low income	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ -	The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure support specific areas in which system resiliency/hardening is a focus. This specific project is to address contingency load at risk which is a component of resiliency.
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	This project does not have uncompensated social or environmental effects.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Conservation and community benefits	$ -	This project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	$ -	This project does not directly impact Public Health
Benefit	Societal	National Security and US international influence	$ -	This project does not impact National Security.

Attachment 5-4 – Weaver Hill Substation Project

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	This project will provide substantial capacity, voltage, and reliability benefits.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Neutral	This project does not impact the Rhode Island economy.
Address the challenge of climate change and other forms of pollution	Neutral	This project does not directly impact climate change but increases the localized system's hosting capacity. The increased hosting capacity could be used by renewable generation which would help address the challenges of climate change.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This project does not directly facilitate customer investments but increases the localized system's hosting capacity. The increased hosting capacity could reduce interconnection costs for customers.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances	This project, as a system improvement, reimburses previous interconnecting customer's system modification costs. Equipment that was initially paid for by specific interconnecting customer but is soon used for all customers may be reallocated to the system customers.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral	This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives.

Docket 4600 Benefit-Cost Framework

Project Name:	Weaver Hill Substation
Area Study:	Central RI West

Problem: There are predicted loading and voltage concerns on certain Hopkins Hill and Coventry substation feeders. The loading concerns include feeders predicted to be near or in excess of thermal ratings. The voltage concerns are similarly at or below guidelines. These same feeders are approaching contingency load-at-risk limits. Furthermore, many of the area feeders have circuit frequency and duration metrics above system averages.

Preferred Plan: Install a new substation on Weaver Hill Rd. This work includes extension of the 3309 and 3310 lines from Nooseneck Hill and Weaver Hill Roads in West Greenwich to a Rhode Island Energy owned property on Weaver Hill Rd, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.

Alternate Plan: Install a new substation on Bell Schoolhouse Road (Pine Hill substation). This work includes extension of the 3310 line from Route 3 north of Route 102 to a Rhode Island Energy owned property at the intersection of New London Turnpike and Bell Schoolhouse Road, Exeter referred to as Pine Hill substation. The work also includes the installation of a new new 34.5 kV line from the new Wickford Junction substation to Pine Hill substation, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.

Summary of Benefit - Cost Analysis

Preferred Plan	
Benefit Cost Ratio	0.67
Net Benefit/Cost	$ (14,860,000)
Alternate Plan	
Benefit Cost Ratio	0.58
Net Benefit/Cost	$ (26,180,000)

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (44,600,000.00)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ -	Transmission project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This project does not directly affect energy usage but does increase the system's hosting capacity for distributed generation. The distributed generation enabled by this project could then affect energy pricing.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	$ -	This project does not impact retail supplier risk premium.
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This project does not impact capacity costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This project does not impact transmission ancillary services.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ 29,740,000.00	This project, as a system improvement, reimburses previous interconnecting customer's system modification costs. This benefit is included in the NPV of the project costs. This benefits does not consider depreciation or acceleration factors.
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This project does not impact transmission capacity costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This project does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This project does not directly impact DRIPE, but the distributed generation enabled by this project could impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This project does not directly impact greenhouse gas compliance costs, but the renewable generation enabled by this project could impact greenhouse gas compliance costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This project will be built to the latest worker safety standards.
Benefit	Power System	Distribution system performance	$ -	This project will provide for new transformer and feeder capacity to address projected loading concerns. Loading and voltage monitoring and control equipment will also be installed that will be used to improve the performance of the localized area.
Benefit	Power System	Utility low income	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ -	The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure support specific areas in which system resiliency/hardening is a focus. This specific project is to address feeders with circuit frequency and duration metrics higher than system averages.
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This project does not directly impact customer empowerment.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Conservation and community benefits	$ -	This project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	$ -	This project does not directly impact Public Health
Benefit	Societal	National Security and US international influence	$ -	This project does not impact National Security.

Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Cost	Power System	Distribution capacity costs	$ (62,680,000.00)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	$ -	Transmission project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	$ -	This project does not directly affect energy usage but does increase the system's hosting capacity for distributed generation. The distributed generation enabled by this project could then affect energy pricing.
Benefit	Power System	Renewable Energy Credit Cost / Value	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	$ -	This project does not impact retail supplier risk premium.
Benefit	Power System	Forward Commitment: Capacity Value	$ -	This project does not impact capacity costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	$ -	This project does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	$ 36,500,000.00	This project, as a system improvement, reimburses previous interconnecting customer's system modification costs. This benefit is included in the NPV of the project costs. This benefit does not consider depreciation or acceleration factors.
Benefit	Power System	Electric Transmission Capacity Costs / Value	$ -	This project does not impact transmission capacity costs.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	$ -	This project does not impact the option value of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	$ -	This project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	$ -	This project does not directly impact DRIPE, but the distributed generation enabled by this project could impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	$ -	This project does not directly impact greenhouse gas compliance costs, but the renewable generation enabled by this project could impact greenhouse gas compliance costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	$ -	This project will be built to the latest worker safety standards.
Benefit	Power System	Distribution system performance	$ -	This project will provide for new transformer and feeder capacity to address projected loading concerns. Loading and voltage monitoring and control equipment will also be installed that will be used to improve the performance of the localized area. The alternative is not optimally located as compared to the recommended plan.
Benefit	Power System	Utility low income	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	$ -	The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure support specific areas in which system resiliency/hardening is a focus. This specific project is to address feeders with circuit frequency and duration metrics higher than system averages.

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Quantitative Assessment NPV (2023)	Qualitative Assessment:
Benefit	Customer	Program participant / prosumer benefits / costs	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	$ -	This project does not have uncompensated social or environmental effects.
Benefit	Societal	Conservation and community benefits	$ -	This project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	$ -	This project does not directly impact economic development.
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	$ -	This project does not directly impact Public Health
Benefit	Societal	National Security and US international influence	$ -	This project does not impact National Security.

Section 3
Vegetation Management Plan

Proposed FY 2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

Section 3: Vegetation Management

The Company's Vegetation Management ("VM") Program is an essential component of the ISR Plan to maintain the safety and reliability of the electric distribution network. Trees have a significant impact on reliability. In CY 2021 trees were the leading cause of customer interruptions (26%) with 121,540 customers experiencing outages due to tree conditions. In addition, keeping vegetation clear from conductors increases safety for the workforce and public, increases operational efficiencies, and reduces wildfire risk. The Company historically has had a strong VM program. Building on these successes, the Plan will incorporate the use of data analytics, technology, and industry best practices into the design and daily operations of every vegetation management activity.

Cycle Pruning

In the 21-Month ISR Plan, the Company proposes a budget of $16.8 million for its cycle pruning program. This program is designed to ensure that the vegetation growth along the overhead portion of the Company's distribution network does not interfere with the safe and reliable performance of the electric network. Cycle pruning includes the scheduling of every distribution circuit for pruning on a fixed timeframe or rotation. Cycle pruning is based on dimension clearance specifications and is designed to maintain an acceptable vegetation clearance. A consistent and well thought out cycle pruning program helps maintain service reliability and supports the efficient management of the overhead network. Managing the vegetation clearance properly helps to avoid interruptions caused by phase-to-phase tree contact and makes the network more accessible to line crews, greatly aiding in power restoration following an interruption. Lastly, this activity also provides the clearance necessary to accurately inspect overhead wires to identify issues or potential issues.

The Company's traditional four-year cycle will be optimized using data analytics to pinpoint the annual feeder list. Examples of optimization are: a circuit along the seacoast in Westerly has more growing degree days, thus enhancing growth and making the case for a cycle trim interval of less than four years. A circuit in Burrillville, in the northwest of the State, has less growth and may be scheduled for an interval of more than four years.

On-Cycle Outage Risk Reduction work

In the 21-Month ISR Plan, the Company proposes a budget of $0.6 million to address specific vegetation and outage risks as needed on each circuit as the circuit is being worked. For this approach each circuit will be examined prior to scheduled cycle pruning using data analytics to identify areas where tree-related outage risks are high. Data analytics and field observations will prescribe the appropriate work required to lower risk of interruption. These include hazard tree removal, targeted heavy overhang removal, dying trees, structurally deficient trees, and weak wooded species removal. Issues identified will be addressed as the crews are on the circuit. Once the circuit has been completed, all known risks have been addressed and crews will not need to return to the feeder until it is on the schedule again. An additional benefit of the on-cycle risk reduction work will be the reduction of pocket of poor performance spending.

Off-Cycle Outage Risk Reduction work (Hazard tree)

In the 21-Month ISR Plan, the Company proposes a budget of $1.0 million to continue to proactively identify and remove hazard trees due pest infestations. In previous years, the Company addressed large-scale tree mortality due to the Spongy Moth (formerly known as the Gypsy Moth). The Emerald Ash Borer is beginning to create similar risk to the system. The need for off-cycle risk reduction work must be in the mix of activities to prevent this pest from causing problems that are currently affecting other utilities. At the Open Meeting on March 20, 2018 in Docket No. 4783, the Commission directed the Company to include a summary in its FY 2019 ISR quarterly reports of the pest-related damaged trees removed. The Company will continue to tabulate trees removed due to pests.

Sub-Transmission

In the 21-Month ISR Plan, the Company proposes a budget of $1.1 million for VM activities on the sub-transmission (Sub-T 22kv/33kV) network. Much like distribution cycle pruning, the Sub-T circuits will be on an optimized cycle. Activities include vegetation management typical for the distribution circuits, as well as herbicide application and mowing floor treatments. The outage risks due to trees on the Sub-T system are quite high and increasing due to large DG customers added to the Sub-T system. The Company will begin incorporating the use of Lidar technology to quantify risks to the system. This method of remotely capturing field conditions will allow for more accurate distance and vegetation health measurements.

Along with historical information, the Company will leverage the Lidar data to identify and address the locations to prevent interruptions.

Traffic Control Measures

In the 21-Month ISR Plan, the Company proposes a budget of $1.6 million for traffic control. In order to safely perform vegetation management in the communities served, appropriate traffic control measures must be employed. These include personnel that flag, police officers, and using crash trucks and arrow boards on busy highways. These costs are often driven by factors outside the Company's control such as municipal requirements, work locations, and hourly rates set by others.

The Company continues to adapt its VM program to minimize traffic control costs. Historically, the Company has separately identified police and flagger costs to allow for clear discussions with municipalities; employed third party flagging services; coordinated work with the Company's electric and gas construction groups; and notified the community relations team of upcoming work. During the 21-Month Plan, the Company will begin requesting vendor bids for cycle trim work that include traffic control in the pricing of the work, instead of as a pass-through cost. This will help ensure that each vendor manages costs effectively and reduces the risks of a budget overrun.

Pockets of Poor Performance

In the 21-Month ISR Plan, the Company proposes a 21-month budget of $0.2 million to continue to focus on pockets of poor performance. In these areas, customers are experiencing many tree-related outages that the Company's current routine programs have not been able to address. Under this spending category a more prescriptive approach is taken that focuses on trees outside of the normal scope of work. In its most recent analysis, the Company has seen a 60% reduction in tree events and a 49% reduction in customers interrupted in the areas where pockets of poor performance work have been performed. The Company anticipates including Pockets of Poor Performance spending in the ISR Plan for a limited time. With the incorporation of data analytics and technology into the VM program, these pockets will be addressed as each feeder is worked in its normal cadence.

Core Activities

In the 21-Month ISR Plan, the Company proposes a budget of $2.9 million for the essential VM activities to efficiently maintain the safety and reliability of the network and to address customer needs. This work includes responding to internal and external customers' requests for vegetation-related work. It also includes responding to emergency calls to remove trees or limbs from wires and performing vegetation work necessary to restore power. The Company has limited discretion over the timing of these activities. Spending for each core activity varies from year-to-year depending on customer calls, weather, and system requirements.

21-Month Vegetation Management Budget

As detailed in Section 3, Chart 1 below, the 21-Month Electric ISR Plan proposes to spend approximately $24.0 million for the 21-month period.

Section 3 – Chart 1

Vegetation Management Spending
($000)

Description	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Actual	FY 2022 Actual	NG FY 2023 Budget (Dkt. 5209)	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
Cycle Pruning (with Enhanced Trimming)	$5,458	$5,995	$5,540	$5,968	$6,540	$7,300	$7,690	$9,078	$16,768
Risk Reduction Work - on cycle	0	0	0	0	0	0	200	350	550
Risk Reduction - off cycle (formerly Hazard Tree – EHTM)	1,113	1,150	2,230	1,653	1,543	1,750	500	500	1,000
Sub-T (off & on road)	468	358	616	397	481	350	350	750	1,100
Police/Flagman Detail	910	788	746	768	873	775	630	933	1,563
Pockets of Poor Performance	0	0	0	200	235	200	100	75	175
Core Crew incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.	1,567	1,448	1,385	1,700	1,591	1,500	1,125	1,750	2,875
Total	**$9,515**	**$9,739**	**$10,517**	**$10,686**	**$11,262**	**$11,875**	**$10,595**	**$13,436**	**$24,031**

Section 4
Inspection and Maintenance and Other O&M

Proposed FY 2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

Section 4: 21-Month Inspection and Maintenance ("I&M") Plan & Other O&M

Inspection and Maintenance Program

This program is intended to address deteriorated assets to ensure that the distribution and sub-transmission system is safe, reliable, and environmentally sound. Asset replacement prior to failure provides incremental safety benefits for both the public and our employees. In addition to asset replacement, testing for elevated voltage should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. The Company originally introduced spending for the I&M program to achieve a five-year inspection and repair cycle. Through discussions with the Division and with the need to prioritize other projects, the spend for I&M programs decreased throughout the past years. The I&M program was streamlined to continue to inspect on a five-year cycle but focus on the highest priority issues including Level 1s, Level 9s, potted porcelain cutouts and some guying issues. Level 1 maintenance items are repaired or replaced within 30 days. Level 9 priority conditions are targeted for completion within 120 days. Although currently on track, if any Level 9 priority item was not field completed within the targeted 120 days, the Company will perform a repeat site visit to monitor its current field condition. Potted porcelain cutouts and guying issues depend on site specific detail and severity of the condition. This streamlined I&M program allows the Company to repair the most significant items efficiently and on time, while still drawing from the backlog of lower priority work, with discretion. The lower priority finds, formerly called Level 2s and 3s, are now captured as "low priority" and will only be progressed to construction if required to address a specific need, because higher priority work generally exists.

Periodic inspection of equipment also provides for the avoidance of potential environmental problems such as insulating fluid leaks/spills from assets such as transformers and capacitor banks. The program is also intended to satisfy Section 214 of the National Electric Safety Code, which outlines inspection of equipment guidelines for electric utilities.

In addition to addressing deteriorated assets, the data collected during the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. As discussed in Section 2, deteriorated equipment is one of the top three drivers affecting customers, accounting for 15% of all interruptions in CY 2021. Although the I&M program is not a reliability-based program, the Company believes that the program is an essential component to fulfilling its obligation to provide safe, reliable, and cost-effective electric delivery service to customers in Rhode Island. The Company's proposal for each of the program components is as follows:

- Continue the five-year inspection cycle and repair "high priority" items in the short-term intervals stated and use discretion to determine which lower priority repairs should be pursued.
- Underground I&M inspections will continue to be performed as part of normal working inspections.
- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.
- Underground Manual Contact Voltage testing will continue on a five-year cycle.

- Street Light Manual Contact Voltage testing will continue on a three-year cycle.
- Mobile Contact Voltage Testing will test 20 percent of the Designated Contact Voltage Risk Areas ("DCVRA's") designated in Docket No. 4237-A.

21-Month Inspection and Maintenance Budget

The Company proposes a 21-month O&M budget for the I&M program of $1.6 million in the 21-Month ISR Plan. O&M costs include program spending and OPEX related to Capex, the O&M costs necessary to complete the capital construction and removal. Associated capital costs, which are included in the capital budget in Section 2 of this Electric ISR Plan, are $5.2 million. Removal costs are $0.5 million. The charts below show the break down by fiscal year.

Section 4 – Chart 1
I&M Program Costs
($000)

CY 2023 9 Mos. 4/1/23-12/31/23	O&M	Capital	Cost of Removal
I&M Program Spending	$338	$2,256	$256
I&M Opex Related to Capex	436	0	0
Total	**$774**	**$2,256**	**$256**

CY 2024 12 Mos. 1/1/24-12/31/24	O&M	Capital	Cost of Removal
I&M Program Spending	$450	$2,961	$225
I&M Opex Related to Capex	405	0	0
Total	**$855**	**$2,961**	**$225**

21-Month ISR Plan 4/1/23 - 12/31/24	O&M	Capital	Cost of Removal
I&M Program Spending	$788	$5,217	$481
I&M Opex Related to Capex	841	0	0
Total	**$1,629**	**$5,217**	**$481**

Other O&M Budget

As discussed in Section 2, although the Company will no longer deploy VVO/CVR on targeted feeders, for the equipment installed, ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing exist. As shown on the table below, in the 21-Month ISR Plan the Company has proposed a budget for O&M spending $0.7 million.

In the 21-Month ISR Plan, the Company's proposes a budget of $50,000 for potential O&M costs associated with the development of the Long-Range Plan.

In the 21-Month ISR Plan, the Company proposes to a budget of $3.2 million related to Grid Modernization.

Section 4 – Chart 2
21-Month Other O&M Costs
($000)

Other O&M Spending	CY 2023 9 Mos. 4/1/23-12/31/23	CY 2024 12 Mos. 1/1/24-12/31/24	21-Month ISR Plan 4/1/23 - 12/31/24
VVO/CVR	$303	$439	$742
System Planning & Protection Study	25	25	50
Grid Modernization	1,506	1,687	3,193
Total	**$1,834**	**$2,151**	**$3,985**

The sections listed below are following:

Section 5: Revenue Requirement

Section 6: Rate Design

Section 7: Bill Impacts

Section 5
Revenue Requirement

Proposed FY 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

Section 5: Revenue Requirement 21-Month Proposal

Introduction

The attached proposed revenue requirement calculations reflect the revenue requirement related to the Company's proposed investment in its Electric ISR Plan for the nine-month period from April 1, 2023 through December 31, 2023 ("CY 2023") and the twelve months from January 1, 2024 through December 31, 2024 ("CY 2024"). The Company's prior year Electric ISR Plan for the period April 1, 2022 through March 31, 2023 approved in Docket No. 5209 is referenced in this section as "FY 2023-NG".

As shown on Attachment 1, Page 1, Column (b), the Company's CY 2023 Electric ISR Plan cumulative revenue requirement is $44,501,333 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and other programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the CY 2023 Property Tax Recovery Adjustments Lines 1, 2, and 3 of Column (b) reflect the forecasted CY 2023 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,595,000, $774,000, and $1,834,000, respectively, which are described in Section 3 and Section 4 of this document. The CY2023 revenue requirement was reduced by $1,119,763 related to the impact of PPL Rhode Island Holdings, LLC's[1] acquisition of 100 percent of the outstanding shares of common stock of the Company from National Grid

[1] PPL Rhode Island Holdings, LLC is a wholly owned indirect subsidiary of PPL Corporation.

USA ("National Grid") on May 25, 2022 (the "Acquisition") on the ISR rate base as described further in the joint pre-filed direct testimony of witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore, and Natalie Hawk. Also, shown on Attachment 1, Page 1, Column (c), the Company's CY 2024 Electric ISR Plan cumulative revenue requirement is $67,073,688 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and other programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the CY 2024 Property Tax Recovery Adjustments. Lines 1, 2, and 3 of Column (c) reflect the forecasted CY 2024 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $13,436,000, $855,000, and $2,151,000, respectively, which are described in Section 3 and Section 4 of this document. The CY 2024 revenue requirement was reduced by $1,502,563 related to the impact of the sale on the ISR rate base as described further in the testimony of witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore and Natalie Hawk.

The CY 2023 revenue requirement of $67,073,688, associated with the Company's incremental capital investment in electric utility infrastructure of, is shown on Attachment 1, Page 1, Line 17. This amount includes (1) the $2,052,168 revenue requirement on CY 2023 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 29, (2) the CY 2023 revenue requirements on incremental ISR capital investment for FY 2018 through FY 2023-NG totaling $25,072,283 and (3) the CY 2023 Property Tax Recovery Adjustment of

$5,293,646 from Attachment 1, Page 42. Importantly, the incremental capital investment for the CY 2023 Electric ISR revenue requirements exclude capital investment embedded in base distribution rates in Docket No. 4770 for FY 2018 through CY 2023. Incremental electric capital investment for this purpose is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base distribution rates, net of depreciation expense attributable to general plant. The total annual CY 2023 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $45,621,096, as reflected on Attachment 1, Page 1, Column (b) on Line 18, and is equal to the sum of Lines 4 and 17. Line 19 represents the adjustment of ($1,119,763) related to the tax hold harmless on Section 5, Attachment 2. Finally, Line 21 reflects the incremental CY 2023 revenue requirement adjustment of a decrease of $5,219,991 below the FY 2023-NG ISR Plan revenue requirement.

The CY 2024 revenue requirement of $52,134,252 associated with the Company's incremental capital investment in electric utility infrastructure, is shown on Attachment 1, Page 1, Line 17. This amount includes (1) the $6,257,002 revenue requirement on CY 2024 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 33, (2) the CY 2024 revenue requirements on incremental ISR capital investment for FY 2018 through CY 2023 totaling $37,723,589 and (3) the CY 2024 Property Tax Recovery Adjustment of $8,153,661 from Attachment 1, Page 42. Importantly, the incremental capital investment for the CY 2024 Electric ISR revenue requirements exclude capital investment embedded in base distribution rates in Docket No. 4770 for FY 2018 through CY 2024. Incremental electric capital investment for this purpose is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base distribution rates, net of depreciation expense attributable to general plant. The total annual CY 2024 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $68,576,252, as reflected on Attachment 1, Page 1, Column (c) on Line 18, and is equal to the sum of Lines 4 and 17. Line 19 represents the adjustment of ($1,502,563) related to the tax hold harmless on Section 5, Attachment 2. Finally, Line 21 reflects the incremental CY 2024 revenue requirement adjustment of $22,572,355 above the CY 2023 ISR Plan revenue requirement.

Operation and Maintenance Expenses

As previously noted, the Company's CY 2023 Electric ISR Plan revenue requirement includes $10,595,000 of VM expenses, $774,000 of I&M expenses, and $1,834,000 of Other Program O&M expenses as shown on Page 1, Lines 1 through 3 in Column (b) of Attachment 1. The Company's CY 2024 Electric ISR Plan revenue requirement includes $13,436,000 of VM expenses, $855,000 of I&M expenses, and $2,151,000 of Other Program O&M expenses as shown on Page 1, Lines 1 through 3 in Column (c) of Attachment 1.

Electric Infrastructure Investment

Incremental Capital Investment

Page 29 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with CY 2023 in the 21-month Electric ISR Plan and Page 33 of Attachment 1 calculates the revenue requirement of incremental capital investment associated with CY2024 in the 21-month Electric ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment and estimated cost of removal were obtained from Chart 18 of Section 2 in this Plan. The CY 2023 and CY 2024 revenue requirements also include the incremental capital investment associated with the Company's FY 2018 through FY 2023-NG Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4770 for FY 2018 through FY 2023-NG. Page 36 of Attachment 1 calculates the incremental FY 2018 through FY 2023-NG ISR capital investment and the related incremental cost of removal, incremental retirements, and incremental tax net operating loss ("NOL") position for the FY 2023-NG electric ISR revenue requirement. Docket No. 4770 includes three rate years, and the forecasted rate base embedded in each rate year included an estimate of incremental capital, cost of removal, retirements and NOL/NOL utilization through Rate Year 3 which ended on August 31, 2021. Therefore, no estimate of the incremental non-growth capital investment, cost of removal, retirements, or NOL position to be incurred during CY 2023 and CY 2024 were included in Docket No. 4770. Therefore, all CY 2023 and CY 2024 ISR-eligible capital is deemed incremental.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. This ISR plan limits the amount of eligible discretionary capital investments to the annual movement in the lesser of cumulative discretionary capital additions, cumulative actual discretionary capital spending or cumulative approved discretionary capital spending since April 1, 2011 (the inception date of the ISR). This limitation on discretionary capital investment will be analyzed as a part of the previously mentioned annual reconciliation of the proposed ISR investment to actual investment activity after the conclusion of the fiscal year.

Incremental Capital Investment Calculation

The ISR mechanism was established to allow the Company to recover outside of base distribution rates its costs associated with plant additions incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. When new base distribution rates are implemented, as was the case in Docket No. 4770, the costs the Company recovers for pre-rate case ISR plant additions are no longer through a separate ISR factor.

Instead, these costs are recovered through base distribution rates, and the underlying ISR plant additions become a component of base distribution rate base from that point forward. The forecast used to develop rate base in the distribution rate case included ISR plant additions levels for FY 2018, FY 2019, and five months of FY 2020 (using the level of plant additions approved in the FY 2018 ISR Plan Proposal as a proxy for FY 2019 and FY 2020). The effective date of new base distribution rates in Docket No. 4770 was September 1, 2018.

Therefore, recovery of the approved FY 2012 through FY 2019 ISR revenue requirement through the ISR factor stopped on August 31, 2018, and all future recovery of those ISR plant additions are through the Company's base distribution rates.

As a result of the implementation of new base distribution rates established in Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR plant additions were included in rate base to be recovered through base distribution rates effective as of that date. The CY 2023 and CY 2024 revenue requirements for incremental FY 2018 through CY 2024 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's rate base. As a result, these incremental vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved amended settlement in Docket No. 4770. This filing is based on the actual ISR plant additions for FY 2018 through FY 2022 and the planned ISR plant additions for FY 2023-NG through CY 2024, which are incremental to the levels reflected in rate base in Docket No. 4770.

Electric Infrastructure Revenue Requirement

The revenue requirement calculations on incremental electric infrastructure investment for vintage years CY 2023 and CY 2024 are shown on Pages 29 and 33 of Attachment 1, respectively. The revenue requirement calculations incorporate the incremental Electric ISR Plan capital investment, cost of removal, retirements, and NOL position. The calculations on Pages 29 and 33 begin with the determination of the depreciable net incremental capital that will be included in the ISR Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in ISR Plan rate base in determining depreciation expense. Retirements, however, do not affect rate base because both plant-in-service and the depreciation reserve are reduced by the installed value of the plant being retired and therefore have no impact on net plant. For purposes of calculating the revenue requirement, incremental plant retirements have been estimated based on the three- year average percentage of retirements to additions during FY 2019 through FY 2022 and have been deducted from the total depreciable capital amount as shown on Pages 29 and 33, Lines 4 through 6. Incremental book depreciation expense on Line 16 is computed based on the net depreciable additions, from Line 6 at the 3.16 percent composite depreciation rate as approved in Docket No. 4770, and as shown on Line 12. The Company has assumed a half year convention for the year of installation. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 10, is combined with the incremental depreciable amount from Line 9 (vintage year ISR Plan allowable capital additions less depreciation expense related to non-general plant except for communication equipment included in base distribution rates) to arrive at the incremental investment on Line 11 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 11 and accumulated depreciation and accumulated deferred tax reserves, as shown on Lines 17 and 22, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 18 through 22, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate, net of any incremental tax NOL or NOL Utilization. The calculation of tax depreciation is described below. The average rate base before the adjustment for deferred tax proration is shown on Line 27. This amount is then adjusted for deferred tax proration on Line 28 to derive the average rate base for ISR on Line 29. The average rate base is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4770, as shown on Line 30, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 31. As reflected on Line 32, incremental depreciation expense is added to this amount. The sum of these amounts reflects the annual revenue requirement associated with the incremental capital investment portion of the Company's Electric ISR Plan on Line 33, which is carried forward to Page 1, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018 through FY 2023-NG incremental ISR Plan capital investments are shown on Attachment 1 at Pages 2, 6, 12, 16, 21 and 25, respectively. These capital investment revenue requirement amounts are added to the total O&M expenses on Attachment 1, Page 1, Line 4, as well as the property tax amount on Page 1, Lines 14 to 16 to derive the total CY 2023 and CY 2024 Electric ISR Plan revenue requirements (before hold harmless adjustment) of $45,621,096 and $68,576,252 as shown on Page 1, Line 19.

Accumulated deferred income tax ("ADIT") included in rate base

As stated above, ADIT is included in the computation of rate base to determine the revenue requirement. Items considered in the computation of deferred taxes are book and tax depreciation, tax repairs deductions, tax gain or loss on retirements, cost of removal, NOL generation or utilization and accumulated deferred tax proration, all of which are discussed further below except for book depreciation. Although, this 21-Month Electric ISR plan covers forecasted periods for CY 2023 and CY 2024, the ADIT to be included in CY 2023 and CY 2024 reflects the accumulated deferred tax impact of the Acquisition and the commitments PPL made during the sale proceeding in Docket No. D-21-09.[2]

PPL Corporation ("PPL") and National Grid elected to treat the acquisition as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of the Company at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis

[1] *See* Report and Order, Docket No. D-21-09 at 257, commitment #16 (February 23, 2023).
[2] PPL Rhode Island Holdings, LLC is a wholly owned indirect subsidiary of PPL Corporation.

eliminated most book/tax timing differences and the related net ADIT as of the acquisition date, at which time PPL began depreciating the new tax basis and started the tracking of book and tax timing differences as if PPL purchased a new asset in the year of acquisition. The revenue requirement of each vintage year reflects the elimination of ADIT in the "PPL 5/25/22 – 12-31-2022" column of the FY March 2023 sub-period. This includes the elimination of accumulated deferred taxes on any NOL balances that existed prior to PPL's acquisition date as National Grid will have utilized all of the Company's NOLs as a result of the sale. In addition, the tax depreciation calculation for each respective vintage year reflects tax depreciation on the new tax basis that is equivalent to Company's net book basis as of the Acquisition date. PPL will reflect the impact of any changes to pre-acquisition computations in its FY 2023-NG reconciliation filing.

<u>Accumulated Deferred Income Tax Proration Adjustment</u>

The Electric ISR Plan includes a proration calculation with respect to the ADIT balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). This regulation sets forth normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing that includes capital expenditures, book depreciation expense and ADIT related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the ADIT balances are in rate base. This filing includes the FY 2018 through CY 2024 proration calculations at Attachment 1, on Pages 4, 5, 8, 9, 14, 15, 18, 19, 23, 24, 27, 28, 31, 32 and 35, respectively, the effects of which are included in each year's respective revenue requirement.

Tax Depreciation Calculation

The tax depreciation calculations for CY 2023 and CY 2024 are provided on Attachment 1, Pages 30 and 34. The tax depreciation amount assumes that a portion of the incremental capital investment, as shown on Line 1 of Pages 29 and 33, will be eligible for immediate deduction on the Company's corresponding CY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[3]

In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Pages 30 and 34, Lines 3 through 14 for CY 2023 and CY 2024, respectively. In 2010, Congress passed the Tax Relief, Unemployment Insurance

[3] In 2009, the Internal Revenue Service (IRS) issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and which is eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. Since that time, the Company has taken a capital repairs deduction on all subsequent FY tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the ISR Plan.

Reauthorization, and Job Creation Act of 2010 (the Act), which provided for an extension of bonus depreciation. Specifically, the Act provides for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013 and then extended further through December 31, 2017 through the Protecting Americans from Tax Hikes ("PATH") Act. As noted in the Company's previous Electric ISR filings, the Tax Cuts and Jobs Act of 2017 ("Tax Act") went into effect on December 22, 2017. The 2017 Tax Act has many elements, but two particular aspects have an impact on the Electric ISR Plan revenue requirement. The first is the reduction of the federal income tax rate from 35 percent to 21 percent commencing January 1, 2018. The second 2017 Tax Act element affecting the Electric ISR Plan revenue requirement is changes to the bonus depreciation rules eliminating bonus depreciation for certain capital investments, including ISR-eligible investments effective September 28, 2017. Property acquired prior to September 28, 2017 and placed in service during tax years beginning after December 31, 2017 is allowed bonus depreciation. The Company's original interpretation of the 2017 Tax Act was that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. Based on bonus rules for long production period property, however, the Company included a deduction for bonus depreciation on its FY 2019 tax return and revised its estimate of FY 2020 bonus depreciation. Starting in FY 2021, the Company can no longer take bonus depreciation. The Company's 21-month revenue requirements include the above impacts of the 2017 Tax Act on vintage FY 2018 through CY 2024 investment.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System ("MACRS") tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a §481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal ("COR"). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100 percent deductible. The vintage FY 2018 through FY 2023-NG tax depreciation calculations in this filing include an additional tax deduction related to this change in accounting issue. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and COR. These annual total tax depreciation amounts are carried over to Page 21 of Attachment 1, Line 14 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for CY 2024 on Page 34 and for FY 2018 through FY 2023-NG on Attachment 1, Pages 3, 7, 13, 17, 22, and 26, respectively.

The Company continues to monitor for new guidance pertaining to the Tax Act and any resulting impacts to its pending rate requests. As of this filing, the Company has not yet evaluated the FY 2022 tax return to determine whether any revisions are required to its calculation of accumulated deferred income taxes included in the vintage revenue requirements calculations in this docket.

The Acquisition was completed during the period ending March 31, 2023 and will have an impact on tax NOLs utilized in the FY 2023-NG revenue requirement. The Company will reflect the impact of any additional NOL utilization on its ADIT balance included in the calculation of ISR rate base in its FY 2023-NG reconciliation filing.

Federal Net Operating Loss

Tax NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the US tax code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions had exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2018, with the exception of FY 2011 and FY 2017. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future.

As a result of the 2017 Tax Act, the Company originally did not expect to generate new NOLs in FY 2018 or FY 2019 and anticipated it would begin to utilize prior years' NOLs in FY 2020. Therefore, estimated NOL utilization is included in base distribution rates in Docket 4770, and the calculation of ADIT in this filing includes only the incremental amount of forecasted NOL utilization in the periods in which the benefit would be reflected in the Company's federal income tax returns.

NOL utilization is an increase to the Company's ADIT and will result in a credit or reduction in the calculation of rate base.

<u>Property Tax Recovery Adjustment</u>

The Property Tax Recovery Adjustment is shown on Pages 40 through 42 of Attachment 1. The method used to recover property tax expense under the Electric ISR Plan was modified by the rate case settlement agreement in Docket No. 4323 and continued under the Amended Settlement Agreement in Docket No. 4770. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The Property Tax Recovery Adjustment also includes the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative Plan net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation. The CY 2023 and CY 2024 revenue requirements include $5,293,646 and $8,153,661, respectively for the Net Property Tax Recovery Adjustment, as shown on Page 1, Lines 15 and 16.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Annual Revenue Requirement Summary

Line No.		12 months Approved Fiscal Year 2023-NG (a)	9 Months Calendar Year 2023 (b)	12 months Calendar Year 2024 (c)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$11,875,000	$10,595,000	$13,436,000
2	Current Year Inspection & Maintenance (I&M)	$1,015,000	$774,000	$855,000
3	Current Year Other Programs	$249,000	$1,834,000	$2,151,000
4	**Total O&M Expense Component of Revenue Requirement**	**$13,139,000**	**$13,203,000**	**$16,442,000**
	Capital Investment:			
5	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,946,604	$1,393,487	$1,801,409
6	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$3,965,256	$3,100,171	$3,987,901
7	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,692,039	$4,391,602	$5,663,303
8	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$8,510,363	$6,434,871	$8,292,653
9	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$7,030,129	$3,887,455	$4,994,184
10	Forecasted Revenue Requirement on FY 2023-NG Capital included in ISR Rate Base	$3,944,106	$5,864,698	$7,626,461
11	Forecasted Revenue Requirement on CY 2023 Capital included in ISR Rate Base (9 Months)		$2,052,168	$5,357,679
12	Forecasted Revenue Requirement on CY 2024 Capital included in ISR Rate Base (12 Months)			$6,257,002
13	Subtotal	$31,088,497	$27,124,451	$43,980,591
14	FY 2023-NG Property Tax Recovery Adjustment	$5,493,827		
15	CY 2023-PPL Property Tax Recovery Adjustment (Dec-23)		$5,293,646	
16	CY 2024-PPL Property Tax Recovery Adjustment (Dec-24)			$8,153,661
17	**Total Capital Investment Component of Revenue Requiremen**	**$36,582,324**	**$32,418,096**	**$52,134,252**
18	**Total Revenue Requirement**	**$49,721,324**	**$45,621,096**	**$68,576,252**
19	Per Tax Hold Harmless Adjustment Section 5, Attachment 2, Pages 1 and 2, Line 23		(1,119,763)	(1,502,563)
20	**Total Net Capital Investment Component of Revenue Requiremen**	**$49,721,324**	**$44,501,333**	**$67,073,688**
21	**Incremental Rate Adjustment**		**($5,219,991)**	**$22,572,355**

Column/Line Notes:
Col (a) Docket No. 5209, FY 2023 Electric ISR Plan, Section 5: Attachment 1, Page 1 of 33, Column (b)
Col (b)
1 Vegetation Management, Section 3, Chart 1
2 Other Operations and Maintenance, Section 4, Chart 1
3 Other Operations and Maintenance, Section 4, Chart 2
4 Sum of Lines 1 through 3
5 Page 2 of 46, Line 40 column (i) & (j)
6 Page 6 of 46, Line 42, Column (h) & (i)
7 Page 12 of 46, Line 39, Column (g) & (h)
8 Page 16 of 46, Line 40, Column (f) & (g)
9 Page 21 of 46, Line 39, Column (e) & (f)
10 Page 25 of 46, Line 39, Column (e) & (f)
11 Page 29 of 46, Line 35, Column (a) & (b)
12 Page 33 of 46, Line 33, Column (a)
13 Sum of Lines 5 through 12
15 Page 42 of 46, Line 91, Column (x) × 1,000
16 Page 42 of 46, Line 91, Column (aa) × 1,000
17 Sum of Lines 13 through 16
18 Line 4 + Line 17
19 RIPUC Docket No. 22-53-EL, Section 5, Attachment 2, Pages 1 and 2, Line 23
20 Line 19 + Line 20
21 Column (b) = Line 20 Col (b) - Line 20 Col (a), Column (c) = Line 20 Col (c) - Line 20 Col (b)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)	NG 4/1/22 - 5/24/2022 2023 (f)	PPL 5/25/22 - 12/31/22 2023 (g)	PPL 1/1/23 - 3/31/23 2023 (h)	9 months Calendar Year Dec-2023 (i)	12 months Calendar Year Dec-2024 (j)
	Capital Investment Allowance												
1	*Non-Discretionary Capital*			$3,178,398									
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256									
3	Total Allowed Capital Included in Rate Base	Page 36 of 46, Line 4(a)		$17,816,654	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base												
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$17,816,654	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 36 of 46 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726
	Change in Net Capital Included in Rate Base												
7	Capital Included in Rate Base	Line 3		$17,816,654	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654
10	Cost of Removal	Page 36 of 46 , Line 7 ,Col (a)		$1,719,991	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**
	Deferred Tax Calculation:												
12	Composite Book Depreciation Rate		1/	3.40%	3.26%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/						54	221	90		
14	Proration Percentage		2/						14.79%	60.55%	24.66%	75.00%	
15	Vintage Year Tax Depreciation:												
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 3 of 46, Line 29; then = Page 3 of 46, Column (e)		$13,898,861	$571,028	$528,156	$488,605	$451,903	$61,848	$539,202	$255,945	$782,055	$960,068
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$13,898,861	$14,469,889	$14,998,045	$15,486,650	$15,938,553	$16,000,401				
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/							$539,202	$795,147	$1,577,202	$2,537,270
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$392,049	$751,812	$728,751	$728,751	$728,751	$107,815	$441,243	$179,692	$546,563	$728,751
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$392,049	$1,143,862	$1,872,612	$2,601,363	$3,330,113	$3,437,928	$3,879,172	$4,058,864	$4,605,427	$5,334,177
21	Cumulative Book / Tax Timer	Columns (a) through (f): Line 17 - Line 20, Then Line 18 - Line 20		$13,506,812	$13,326,028	$13,125,433	$12,885,287	$12,608,439	$12,562,472	($3,339,970)	($3,263,716)	($3,028,224)	($2,796,907)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (f)	3/							$3,437,928	$3,437,928	$3,437,928	$3,437,928
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22								$97,959	$174,212	$409,704	$641,021
24	Effective Tax Rate		4/	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (f): Line 21 * Line 24, Then Line 23 * Line 24		$2,836,430	$2,798,466	$2,756,341	$2,705,910	$2,647,772	$2,638,119	$20,571	$36,585	$86,038	$134,614
26	Less: FY 2018 Federal NOL	Year 1 = Page 36 of 46 , Line 15 ,Col (a) ; then = Prior Year Line 26	3/	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	$0	$0	$0	$0
27	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969
28	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 27		$1,262,901	$1,224,936	$1,182,811	$1,132,380	$1,074,242	$1,064,589	$1,445,540	$1,461,553	$1,511,007	$1,559,583
	Rate Base Calculation:												
29	Cumulative Incremental Capital Included in Rate Base	Line 11		$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645
30	Accumulated Depreciation	-Line 20		($392,049)	($1,143,862)	($1,872,612)	($2,601,363)	($3,330,113)	($3,437,928)	($3,879,172)	($4,058,864)	($4,605,427)	($5,334,177)
31	Deferred Tax Reserve	-Line 28		($1,262,901)	($1,224,936)	($1,182,811)	($1,132,380)	($1,074,242)	($1,064,589)	($1,445,540)	($1,461,553)	($1,511,007)	($1,559,583)
32	Year End Rate Base before Deferred Tax Proration	Sum of Lines 29 through 31		$17,881,695	$17,167,848	$16,481,222	$15,802,902	$15,132,290	$15,034,128	$14,211,934	$14,016,228	$13,420,212	$12,642,885
	Revenue Requirement Calculation:												
33	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 and 2 = 0; then Average of (Prior + Current Year Line 32)	5/	$8,940,848	$17,524,772	$16,824,535	$16,142,062	$15,467,596	$14,574,259	$14,574,259	$14,574,259	$13,718,220	$13,031,549
34	Proration Adjustment	Page 4 of 46 & Page 5 of 46				($1,818)	($2,165)	($2,495)	$1,156	$1,156	$1,156	$2,707	$1,969
35	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$8,940,848	$17,524,772	$16,822,717	$16,139,898	$15,465,101	$14,575,415	$14,575,415	$14,575,415	$13,720,928	$13,033,517
36	Pre-Tax ROR	Page 44 of 46, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
37	Proration	Line 14	2/						14.79%	60.55%	24.66%	75.00%	
38	Return and Taxes	Cols (a) through (e) and (j): L 35 * L 36; Cols (f) through (i): L 35 * L 36 * L 37	2/	$735,832	$1,442,289	$1,384,510	$1,328,314	$1,272,778	$177,469	$726,307	$295,781	$846,924	$1,072,658
39	Book Depreciation	Line 19		$392,049	$751,812	$728,751	$728,751	$728,751	$107,815	$441,243	$179,692	$546,563	$728,751
40	**Annual Revenue Requirement**	Line 38 + Line 39		**$1,127,881**	**$2,194,101**	**$2,113,260**	**$2,057,064**	**$2,001,528**	**$285,284**	**$1,167,550**	**$475,473**	**$1,393,487**	**$1,801,409**

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018, per Page 12 of 18
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12
2/ Columns (f) through (h) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (i) is prorated for the 9-month CY 2023 plan.
3/

National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ The Federal Income Tax rate changed from 35% to 21% on Janurary 1, 2018 per the Tax Cuts and Jobs Act of 2017
5/ Columns (f) through (h) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 32, Column (e) and the end of the fiscal year on Line 32, Column (h). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investments

Line No.				Fiscal Year 2018 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 2 of 46, Line 3		$17,816,654	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%					
3	Capital Repairs Deduction	Line 1 * Line 2		$1,603,499	NG MACRS basis:	Line 22, Column (a)		$7,910,074	
4		`						Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$17,816,654	FY Mar-2018	3.750%		$296,628	$13,898,861
7	Less Capital Repairs Deduction	- Line 3		($1,603,499)	FY Mar-2019	7.219%		$571,028	$14,469,889
8	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7		$16,213,155	FY Mar-2020	6.677%		$528,156	$14,998,045
9	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2021	6.177%		$488,605	$15,486,650
10	Plant Eligible for Bonus Depreciation	Line 8 * Line 9		$16,213,155	FY Mar-2022	5.713%		$451,903	$15,938,553
11	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%	FY Mar-2023 (Apr-May 2022)	5.285%	0.782%	$61,848	$16,000,401
12	Bonus depreciation 50% category	50% * 34.28%	2/	17.14%					
13	Bonus depreciation 40% category	40% * 44.23%	2/	17.69%	PPL Acquisition - May 25, 2022				
14	Bonus depreciation 0% category	0% * 5.11%	2/	0.00%	Book Cost	Line 1, Column (a)		$17,816,654	
15	Total Bonus Depreciation Rate	Line 11 + Line 12 + Line 13 + Line 14		51.21%	Cumulative Book Depreciation	- Page 2 of 46, Line 20, Col (f)		($3,437,928)	
16	Bonus Depreciation	Line 10 * Line 15		$8,303,081	PPL MACRS basis:	Line 14(e) + Line 15(e)		$14,378,726	
17									
18	Remaining Tax Depreciation				FY Mar-2023 (Jun-Dec 2022)	3.750%		$539,202	$539,202
19	Plant Additions	Line 1		$17,816,654	FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$255,945	$795,147
20	Less Capital Repairs Deduction	Line 3		$1,603,499	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$782,055	$1,577,202
21	Less Bonus Depreciation	Line 16		$8,303,081	CY 2024	6.677%		$960,068	$2,537,270
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 19 - Line 20 - Line 21		$7,910,074	CY 2025	6.177%		$888,174	$3,425,444
23	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	CY 2026	5.713%		$821,457	$4,246,900
24	Remaining Tax Depreciation	Line 22 * Line 23		$296,628	CY 2027	5.285%		$759,916	$5,006,816
25					CY 2028	4.888%		$702,832	$5,709,648
26	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662	CY 2029	4.522%		$650,206	$6,359,854
27	Cost of Removal	Page 2 of 46, Line 10		$1,719,991	CY 2030	4.462%		$641,579	$7,001,433
28					CY 2031	4.461%		$641,435	$7,642,868
29	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 16, 24, 26, and 27		$13,898,861	CY 2032	4.462%		$641,579	$8,284,447
30					CY 2033	4.461%		$641,435	$8,925,882
31					CY 2034	4.462%		$641,579	$9,567,460
32					CY 2035	4.461%		$641,435	$10,208,895
33					CY 2036	4.462%		$641,579	$10,850,474
34					CY 2037	4.461%		$641,435	$11,491,909
35					CY 2038	4.462%		$641,579	$12,133,488
36					CY 2039	4.461%		$641,435	$12,774,923
37					CY 2040	4.462%		$641,579	$13,416,501
38					CY 2041	4.461%		$641,435	$14,057,936
39					CY 2042	2.231%		$320,789	$14,378,726
40						100.00%		$14,378,726	

1/ Capital Repairs percentage is based on the actual results of the FY 2018 tax return.
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2018 tax return
3/ Actual Loss for FY2018
Column (d), Line 11 = MACRS Rate 5.285% / 365 days x 54 days
Column (d), Line 19 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 20 = MACRS Rate 7.219% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 2 of 46, Line 19, column (e); Col (b): Page 2 of 46, Line 19, columns (f) through (h); Col (c): Page 2 of 46, Line 19, column (i)	$728,751	$728,751	$546,563
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 3 of 46, Line 10, column, (e); Col (b): - Page 3 of 46, Sum of Lines 11,18,19, column, (e); Col (c): - Page 3 of 46, Line 20, column, (e)	($451,903)	($856,996)	($782,055)
4	FY18 tax (gain)/loss on retirements		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$276,848	($128,245)	($235,492)
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$58,138	($26,931)	($49,453)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2017				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21%	21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$58,138	($26,931)	($49,453)
15	Net Operating Loss		$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$58,138	($26,931)	($49,453)
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$276,848	($128,245)	($235,492)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$276,848	($128,245)	($235,492)
20	Total FY 2018 Federal NOL				
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0	$0
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$58,138	($26,931)	($49,453)

Line No.	Proration Calculation	Number of Days in Month (d)	Proration Percentage (e)	FY22 (f)	FY23-NG (g)	Apr 1 - Dec 31 2023 (h)
26	April	30	91.78%	$4,447	($2,060)	($4,895)
27	May	31	83.29%	$4,035	($1,869)	($4,276)
28	June	30	75.07%	$3,637	($1,685)	($3,677)
29	July	31	66.58%	$3,225	($1,494)	($3,057)
30	August	31	58.08%	$2,814	($1,304)	($2,438)
31	September	30	49.86%	$2,416	($1,119)	($1,838)
32	October	31	41.37%	$2,004	($928)	($1,219)
33	November	30	33.15%	$1,606	($744)	($619)
34	December	31	24.66%	$1,195	($553)	
35	January	31	16.16%	$783	($363)	
36	February	28	8.49%	$411	($191)	
37	March	31	0.00%	$0	$0	
38	Total	365		$26,574	($12,310)	($22,019)
39	Deferred Tax Without Proration	Line 25		$58,138	($26,931)	($49,453)
40	Average Deferred Tax without Proration	Line 25 * 50%		$29,069	($13,466)	($24,727)
41	Proration Adjustment	Line 38 - Line 40		($2,495)	$1,156	$2,707

Column Notes:

(e)	Sum of remaining days in the year (Col (d)) ÷ 365
(f) through (g)	Current Year Line 25 ÷ 12 × Current Month Col (e)
(h)	Current Year Line 25 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (d)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration			CY24 (a)
1	Book Depreciation	Page 2 of 46, Line 19, column (j)		$728,751
2	Bonus Depreciation			$0
3	Remaining MACRS Tax Depreciation	Page 3 of 46, column, (e)		($960,068)
4	FY18 tax (gain)/loss on retirements			$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($231,317)
6	Effective Tax Rate			21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($48,577)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction			
9	Cost of Removal			
10	Book/Tax Depreciation Timing Difference at 3/31/2017			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		$0
12	Effective Tax Rate			21%
13	Deferred Tax Reserve	Line 11 × Line 12		$0
14	Total Deferred Tax Reserve	Line 7 + Line 13		($48,577)
15	Net Operating Loss			$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($48,577)
	Allocation of FY 2018 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($231,317)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($231,317)
20	Total FY 2018 Federal NOL			
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$0
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20		$0
23	Effective Tax Rate			21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23		$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($48,577)
		(b)	(c)	(d)
	Proration Calculation	Number of Days in Month	Proration Percentage	CY24
26	January	31	91.53%	($3,705)
27	February	29	83.61%	($3,384)
28	March	31	75.14%	($3,042)
29	April	30	66.94%	($2,710)
30	May	31	58.47%	($2,367)
31	June	30	50.27%	($2,035)
32	July	31	41.80%	($1,692)
33	August	31	33.33%	($1,349)
34	September	30	25.14%	($1,018)
35	October	31	16.67%	($675)
36	November	30	8.47%	($343)
37	December	31	0.00%	$0
38	Total	366		($22,320)
39	Deferred Tax Without Proration	Line 25		($48,577)
40	Average Deferred Tax without Proration	Line 25 * 50%		($24,288)
41	Proration Adjustment	Line 38 - Line 40		$1,969

Column Notes:

(c) Sum of remaining days in the year (Col (b)) ÷ 366

(d) Current Year Line 25 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)	NG 4/1/22 - 5/24/2022 2023 (e)	PPL 5/25/22 - 12/31/22 2023 (f)	PPL 1/1/23 - 3/31/23 2023 (g)	9 months Calendar Year Dec-2023 (h)	12 months Calendar Year Dec-2024 (i)
	Capital Investment Allowance											
1	*Non-Discretionary Capital*			$7,452,659								
	Discretionary Capital											
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$25,486,776								
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 36 of 46, Line 4(b)		$32,939,435	$0	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base											
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)		$32,939,435	$0	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 36 of 46 , Line 10 ,Col (b)		($10,649,479)	$0	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914
	Change in Net Capital Included in Rate Base											
7	Capital Included in Rate Base	Line 3, Column (a)		$32,939,435	$0	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435
10	Cost of Removal	Page 36 of 46 , Line 7 ,Col (b)		$101,073								
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**
	Deferred Tax Calculation:											
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770	1/	3.26%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/					54	221	90		
14	Proration Percentage		2/					14.79%	60.55%	24.66%	75.00%	
15	Vintage Year Tax Depreciation:											
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 7 of 46, Line 28 Then = Page 7 of 46 Column (b)		$9,919,837	$1,842,847	$1,704,487	$1,576,848	$215,763	$1,045,985	$496,502	$1,517,089	$1,862,411
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$9,919,837	$11,762,684	$13,467,171	$15,044,019	$15,259,782				
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/						$1,045,985	$1,542,486	$3,059,575	$4,921,986
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$710,499	$1,377,410	$1,377,410	$1,377,410	$203,781	$833,993	$339,635	$1,033,057	$1,377,410
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$710,499	$2,087,909	$3,465,319	$4,842,728	$5,046,509	$5,880,503	$6,220,138	$7,253,195	$8,630,605
21	Cumulative Book / Tax Timer	Columns (a) through(e): Line 17 - Line 20, Then Line 18 - Line 20		$9,209,338	$9,674,775	$10,001,852	$10,201,291	$10,213,273	($4,834,518)	($4,677,652)	($4,193,620)	($3,708,619)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (e)	3/						$5,046,509	$5,046,509	$5,046,509	$5,046,509
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22							$211,991	$368,858	$852,889	$1,337,890
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (e): Line 21 * Line 24, Then Line 23 * Line 24		$1,933,961	$2,031,703	$2,100,389	$2,142,271	$2,144,787	$44,518	$77,460	$179,107	$280,957
26	Add: FY 2019 Federal NOL incremental utilization	Page 36 of 46 , Line 15 ,Col (b)	3/	$991,622	$991,622	$991,622	$991,622	$991,622	$0	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$2,925,583	$3,023,325	$3,092,011	$3,133,893	$3,136,409	$44,518	$77,460	$179,107	$280,957
	Rate Base Calculation:											
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508
29	Accumulated Depreciation	-Line 20		($710,499)	($2,087,909)	($3,465,319)	($4,842,728)	($5,046,509)	($5,880,503)	($6,220,138)	($7,253,195)	($8,630,605)
30	Deferred Tax Reserve	-Line 27		($2,925,583)	($3,023,325)	($3,092,011)	($3,133,893)	($3,136,409)	($44,518)	($77,460)	($179,107)	($280,957)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$29,404,426	$27,929,274	$26,483,178	$25,063,887	$24,857,589	$27,115,487	$26,742,910	$25,608,206	$24,128,946
	Revenue Requirement Calculation:											
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 ÷ 2; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$14,702,213	$28,666,850	$27,206,226	$25,773,533	$25,903,398	$25,903,398	$25,903,398	$26,175,558	$24,868,576
33	Proration Adjustment	Page 8 of 46 & Page 9 of 46		$0	$0	$0	($347)	$3,603	$3,603	$3,603	$27,183	$1,861
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$14,702,213	$28,666,850	$27,206,226	$25,773,185	$25,907,002	$25,907,002	$25,907,002	$26,202,741	$24,870,437
35	Pre-Tax ROR	Page 44 of 46, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration Percentage	Line 14	2/					14.79%	60.55%	24.66%	75.00%	
37	Return and Taxes	Cols (a) through (d) and (i): L 34 * L 35; Cols (e) through (h): L 34 * L 35 * L 36	2/	$1,209,992	$2,359,282	$2,239,072	$2,121,133	$315,441	$1,290,971	$525,735	$1,617,364	$2,046,837
38	Book Depreciation	Line 19		$710,499	$1,377,410	$1,377,410	$1,377,410	$203,781	$833,993	$339,635	$1,033,057	$1,377,410
39	Annual Revenue Requirement	Line 37 + Line 38		$1,920,491	$3,736,691	$3,616,482	$3,498,543	$519,222	$2,124,964	$865,370	$2,650,421	$3,424,247
40	Revenue Requirement of Plant	Year 1 = Line 39*7/12, Then = Line 39		$1,120,287	$3,736,691	$3,616,482	$3,498,543	$519,222	$2,124,964	$865,370	$2,650,421	$3,424,247
41	Revenue Requirement of Intangible	Page 10 of 46, Line 34, Column (l) ~ (aa)		$434,302	$705,779	$655,914	$617,127	$81,808	$392,276	$154,977	$449,750	$563,655
42	**Revenue Requirement**	Line 40 + Line 41		**$1,554,589**	**$4,442,470**	**$4,272,396**	**$4,115,669**	**$601,030**	**$2,517,240**	**$1,020,347**	**$3,100,171**	**$3,987,901**

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12

2/ Columns (e) through (g) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (h) is prorated for the 9-month FY Dec. 2023 plan.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Columns (e) through (g) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (d) and the end of the fiscal year on Line 31, Column (g). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2019 Incremental Capital Investments

Line No.				Fiscal Year 2019 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 6 of 46, Line 3		$32,939,435		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.68%					
3	Capital Repairs Deduction	Line 1 * Line 2		$3,188,562	MACRS basis:	Line 22, Column (a)		$25,527,737	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$32,939,435	FY Mar-2019	3.750%		$957,290	$9,919,837
7	Plant Additions			$0	FY Mar-2020	7.219%		$1,842,847	$11,762,684
8	Less Capital Repairs Deduction	Line 3		$3,188,562	FY Mar-2021	6.677%		$1,704,487	$13,467,171
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$29,750,873	FY Mar-2022	6.177%		$1,576,848	$15,044,019
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2023 (Apr-May 2022)	5.713%	0.85%	$215,763	$15,259,783
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$29,750,873					
12	Bonus Depreciation Rate	1 * 11.65% * 30%	2/	3.50%	PPL Acquisition - May 25, 2022				
13	Bonus Depreciation Rate	1 * 26.75% * 40%	2/	10.70%	Book Cost	Line 1, Column (a)		$32,939,435	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		14.20%	Cumulative Book Depreciation	- Page 6 of 46, Line 20, Col (e)		($5,046,509)	
15	Bonus Depreciation	Line 11 * Line 14		$4,223,136	PPL MACRS basis:	Line 13(e) + Line 14(e)		$27,892,925	
16									
17	Remaining Tax Depreciation				FY Mar-2023 (Jun-Dec 2022)	3.750%		$1,045,985	$1,045,985
18	Plant Additions	Line 1		$32,939,435	FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$496,502	$1,542,486
19	Less Capital Repairs Deduction	Line 3		$3,188,562	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$1,517,089	$3,059,575
20	Less Bonus Depreciation	Line 15		$4,223,136	CY 2024	6.677%		$1,862,411	$4,921,986
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$25,527,737	CY 2025	6.177%		$1,722,946	$6,644,932
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	CY 2026	5.713%		$1,593,523	$8,238,454
23	Remaining Tax Depreciation	Line 21 * Line 22		$957,290	CY 2027	5.285%		$1,474,141	$9,712,596
24					CY 2028	4.888%		$1,363,406	$11,076,002
25	FY19 (Gain)/Loss incurred due to retirements	Per Tax Department	3/	$1,449,776	CY 2029	4.522%		$1,261,318	$12,337,320
26	Cost of Removal	Page 6 of 46, Line 10		$101,073	CY 2030	4.462%		$1,244,582	$13,581,902
27					CY 2031	4.461%		$1,244,303	$14,826,206
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$9,919,837	CY 2032	4.462%		$1,244,582	$16,070,788
29					CY 2033	4.461%		$1,244,303	$17,315,091
30					CY 2034	4.462%		$1,244,582	$18,559,674
31					CY 2035	4.461%		$1,244,303	$19,803,977
32					CY 2036	4.462%		$1,244,582	$21,048,559
33					CY 2037	4.461%		$1,244,303	$22,292,863
34					CY 2038	4.462%		$1,244,582	$23,537,445
35					CY 2039	4.461%		$1,244,303	$24,781,748
36					CY 2040	4.462%		$1,244,582	$26,026,331
37					CY 2041	4.461%		$1,244,303	$27,270,634
38					CY 2042	2.231%		$622,291	$27,892,925
39						100.00%		$27,892,925	

1/ Capital Repairs percentage is the actual result of FY 2019 tax return
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY 2019 tax return
3/ Actual Loss for FY 2019
Column (d), Line 10 = MACRS Rate 5.713% / 365 days x 54 days
Column (d), Line 18 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 19 = MACRS Rate 7.219% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation - Excl. Intangibles	Col (a): Page 6 of 46, Line 19, column (d); Col (b): Page 6 of 46, Line 19, columns (e) through (g); Col (c): Page 6 of 46, Line 19, column (h)	$1,377,410	$1,377,410	$1,033,057
2	Book Depreciation - Intangibles	Col (a): Page 10 of 46, Line 21 - Line 20, Column (l); Col (b): Page 10 of 46, Line 21 - Line 20, Sum of Columns (o), (r), (u); Col (c): Page 10 of 46, Line 21 - Line 20, Column (x)	$494,375	$494,375	$370,781
3	Bonus Depreciation		$0	$0	$0
4	Remaining MACRS Tax Depreciation - Excl. Intangibles	Col (a): - Page 7 of 46, Line 9, column, (e) Col (b): - Page 7 of 46, Sum of Lines 10,17,18, column, (e) Col (c): - Page 7 of 46, Line 19, column, (e)	($1,576,848)	($1,758,250)	($1,517,089)
5	Remaining MACRS Tax Depreciation - Intangibles	Col (a): - (Page 10 of 46, Line 18 - Line 17, Column (l)); Col (b): - (Page 10 of 46, Line 18 - Line 17, Sum of Columns (o), (r), (u)); Col (c): - (Page 10 of 46, Line 18 - Line 17, Column (x))	($256,432)	($513,297)	($684,550)
6	FY 2019 tax (gain)/loss on retirements		$0	$0	$0
7	Cumulative Book / Tax Timer	Sum of Lines 1 through 6	$38,504	($399,762)	($797,800)
8	Effective Tax Rate		21.00%	21.00%	21.00%
9	Deferred Tax Reserve	Line 7 * Line 8	$8,086	($83,950)	($167,538)
	Deferred Tax Not Subject to Proration				
10	Capital Repairs Deduction				
11	Cost of Removal				
12	Book/Tax Depreciation Timing Difference at 3/31/2018				
13	Cumulative Book / Tax Timer	Line 10 + Line 11 + Line 12	$0	$0	$0
14	Effective Tax Rate		21%	21%	21%
15	Deferred Tax Reserve	Line 13 × Line 14	$0	$0	$0
16	Total Deferred Tax Reserve	Line 9 + Line 15	$8,086	($83,950)	($167,538)
17	Net Operating Loss		$0	$0	$0
18	Net Deferred Tax Reserve	Line 16 + Line 17	$8,086	($83,950)	($167,538)
	Allocation of FY 2019 Estimated Federal NOL				
19	Cumulative Book/Tax Timer Subject to Proration	Line 7	$38,504	($399,762)	($797,800)
20	Cumulative Book/Tax Timer Not Subject to Proration	Line 13	$0	$0	$0
21	Total Cumulative Book/Tax Timer	Line 19 + Line 20	$38,504	($399,762)	($797,800)
22	Total FY 2019 Federal NOL		$0	$0	$0
23	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 20 ÷ Line 21) × Line 22	$0	$0	$0
24	Allocated FY 2019 Federal NOL Subject to Proration	(Line 19 ÷ Line 21) × Line 22	$0	$0	$0
25	Effective Tax Rate		21%	21%	21%
26	Deferred Tax Benefit subject to proration	Line 24 × Line 25	$0	$0	$0
27	Net Deferred Tax Reserve subject to proration	Line 9 + Line 26	$8,086	($83,950)	($167,538)

Line No.	Proration Calculation	Number of Days in Month (d)	Proration Percentage (e)	FY22 (f)	FY23-NG (g)	Apr 1 - Dec 31 2023 (h)
28	April	30	91.78%	$618	($6,421)	($15,354)
29	May	31	83.29%	$561	($5,827)	($12,394)
30	June	30	75.07%	$506	($5,252)	($9,726)
31	July	31	66.58%	$449	($4,657)	($7,360)
32	August	31	58.08%	$391	($4,063)	($5,296)
33	September	30	49.86%	$336	($3,488)	($3,524)
34	October	31	41.37%	$279	($2,894)	($2,054)
35	November	30	33.15%	$223	($2,319)	($876)
36	December	31	24.66%	$166	($1,725)	
37	January	31	16.16%	$109	($1,131)	
38	February	28	8.49%	$57	($594)	
39	March	31	0.00%	$0	$0	
40	Total	365		$3,696	($38,372)	($56,586)
41	Deferred Tax Without Proration	Line 27		$8,086	($83,950)	($167,538)
42	Average Deferred Tax without Proration	Line 39 * 50%		$4,043	($41,975)	($83,769)
43	Proration Adjustment	Line 40 - Line 42		($347)	$3,603	$27,183

Column Notes:

(e)	Sum of remaining days in the year (Col (d)) ÷ 365
(f) through (g)	Current Year Line 27 ÷ 12 × Current Month Col (e)
(h)	Current Year Line 27 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (d)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration		CY24 (a)
1	Book Depreciation - Excl. Intangibles	Page 6 of 46, Line 19, column (i)	$1,377,410
2	Book Depreciation - Intangibles	Page 10 of 46, Line 21 - Line 20, Column (aa)	$494,375
3	Bonus Depreciation		$0
4	Remaining MACRS Tax Depreciation - Excl. Intangibles	Page 7 of 46, Line 20, column, (e)	($1,862,411)
5	Remaining MACRS Tax Depreciation - Intangibles	- (Page 10 of 46, Line 18 - Line 17, Column (aa))	($228,081)
6	FY 2019 tax (gain)/loss on retirements		$0
7	Cumulative Book / Tax Timer	Sum of Lines 1 through 6	($218,706)
8	Effective Tax Rate		21.00%
9	Deferred Tax Reserve	Line 7 * Line 8	($45,928)
	Deferred Tax Not Subject to Proration		
10	Capital Repairs Deduction		
11	Cost of Removal		
12	Book/Tax Depreciation Timing Difference at 3/31/2018		
13	Cumulative Book / Tax Timer	Line 10 + Line 11 + Line 12	$0
14	Effective Tax Rate		21%
15	Deferred Tax Reserve	Line 13 × Line 14	$0
16	Total Deferred Tax Reserve	Line 9 + Line 15	($45,928)
17	Net Operating Loss		$0
18	Net Deferred Tax Reserve	Line 16 + Line 17	($45,928)
	Allocation of FY 2019 Estimated Federal NOL		
19	Cumulative Book/Tax Timer Subject to Proration	Line 7	($218,706)
20	Cumulative Book/Tax Timer Not Subject to Proration	Line 13	$0
21	Total Cumulative Book/Tax Timer	Line 19 + Line 20	($218,706)
22	Total FY 2019 Federal NOL		$0
23	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 20 ÷ Line 21) × Line 22	$0
24	Allocated FY 2019 Federal NOL Subject to Proration	(Line 19 ÷ Line 21) × Line 22	$0
25	Effective Tax Rate		21%
26	Deferred Tax Benefit subject to proration	Line 24 × Line 25	$0
27	Net Deferred Tax Reserve subject to proration	Line 9 + Line 26	($45,928)

	Proration Calculation	(b) Number of Days in Month	(c) Proration Percentage	(d) CY24
28	January	31	91.53%	($3,503)
29	February	29	83.61%	($3,200)
30	March	31	75.14%	($2,876)
31	April	30	66.94%	($2,562)
32	May	31	58.47%	($2,238)
33	June	30	50.27%	($1,924)
34	July	31	41.80%	($1,600)
35	August	31	33.33%	($1,276)
36	September	30	25.14%	($962)
37	October	31	16.67%	($638)
38	November	30	8.47%	($324)
39	December	31	0.00%	$0
40	Total	366		($21,103)
41	Deferred Tax Without Proration	Line 27		($45,928)
42	Average Deferred Tax without Proration	Line 39 * 50%		($22,964)
43	Proration Adjustment	Line 40 - Line 42		$1,861

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 27 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	FY 22 Total (l) = (j) + (k)	FY Mar-2023 (Apr-May 2022) (o) = (m) + (n) NG	FY Mar-2023 (Jun-Dec 2022) (r) = (p) + (q) PPL	FY Mar-2023 (Jan-Mar 2023) (u) = (s) + (t) PPL	CY 2023 (Apr-Dec 2023) (x) = (v) + (w) PPL	CY 24 Total (aa) = (y) + (z) PPL
	Capital Investment							
1	Start of Rev. Req. Period		04/01/21	04/01/22	05/25/22	01/01/23	04/01/23	01/01/24
2	End of Rev. Req. Period		03/31/22	05/24/22	12/31/22	03/31/23	12/31/23	12/31/24
3	Investment Name	Per Company's Book						
4	Work Order	Per Company's Book						
5	Total Spend		$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626
6	In ServiceDate	Per Company's Book						
7	Book AmortizationPeriod	Per Company's Book						
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$2,101,094	$1,606,719	$1,540,045	$1,235,938	$1,112,344	$741,563
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$1,606,719	$1,540,045	$1,235,938	$1,112,344	$741,563	$247,188
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$1,853,907	$1,573,382	$1,387,992	$1,174,141	$926,953	$494,375
	Deferred Tax Calculation:							
11	Total Spend							
12	In Service Date							
13	Tax Amortizaton Period	Page 11 of 46						
14	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0	$0
15	Tax Bonus Rate	Per Tax Department						
16	Bonus Depreciation	Year 1 = (L. 5 - L. 14) × L.15, Then = 0	$0	$0	$0	$0	$0	$0
17	Beginning Acc. Tax Balance	(L. 5 - L. 14- L.16)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$3,204,194	$3,460,626	$0	$513,297	$513,297	$1,197,847
18	Ending Acc. Tax Balance	(L. 5 - L. 14- L.16) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$3,460,626	$3,460,626	$513,297	$513,297	$1,197,847	$1,425,928
19	Average Acc. Tax Balance	(Line 17 + Line 18) ÷ 2	$3,332,410	$3,460,626	$256,649	$513,297	$855,572	$1,311,887
20	Beginning Acc. Dep. Balance	Line 5 - Line 8	$1,359,532	$1,853,907	$1,920,581	$2,224,688	$2,348,282	$2,719,063
21	Ending Acc. Dep. Balance	Line 5 - Line 9	$1,853,907	$1,920,581	$2,224,688	$2,348,282	$2,719,063	$3,213,439
22	Average Acc. Dep. Balance	(Line 20 + Line 21) ÷ 2	$1,606,719	$1,887,244	$2,072,635	$2,286,485	$2,533,673	$2,966,251
23	Number of days							
24	Proration Percentage							
25	Average Book / Tax Timer	Line 19 - Line 22	$1,725,691	$232,774	($1,099,542)	($437,224)	($1,258,575)	($1,654,364)
26	Effective Tax Rate							
27	Deferred Tax Reserve	Line 25 × Line 26	$362,395	$48,883	($230,904)	($91,817)	($264,301)	($347,416)
	Rate Base Calculation:							
28	Average Book Balance	Line 10	$1,853,907	$232,774	$840,400	$289,514	$695,215	$494,375
29	Deferred Tax Reserve	Line 27	$362,395	$48,883	($230,904)	($91,817)	($264,301)	($347,416)
30	Average Rate Base	Line 28 - Line 29	$1,491,512	$183,892	$1,071,304	$381,331	$959,516	$841,792
	Revenue Requirement Calculation:							
31	Pre-Tax ROR	year 1 = Page 44 of 46, Line 27, column (e)×7÷12 Then = Page 44 of 46, Line 27(e)						
32	Return and Taxes	Line 30 × Line 31	$122,751	$15,134	$88,168	$31,384	$78,968	$69,279
33	Book Depreciation	Line 9 - Line 8	$494,375	$66,674	$304,107	$123,594	$370,781	$494,375
34	Annual Revenue Requirement	Line 32 + Line 33	$617,127	$81,808	$392,276	$154,977	$449,750	$563,655

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
MACRS Tables For Information Systems

Line No.	Annual Rate: Year			Monthly Cumulative Rate: Year	Period	Cumulative Rate		
1	Yr 1	33.33%	33.33%	1	1	33.33%	2.78%	Yr 1 - Monthly rate
2	Yr 2	44.45%	77.78%	1	2	33.33%		
3	Yr 3	14.81%	92.59%	1	3	33.33%		
4	Net Salvage Value	7.41%	100.00%	1	4	33.33%		
11				1	11	33.33%		
12				1	12	33.33%		
13				2	13	77.78%	3.70%	Yr 2 - Monthly rate
25				3	25	92.59%	1.23%	Yr 3 - Monthly rate
36				3	36	92.59%	0.62%	Yr 3 - Monthly rate
48				4	48	100.00%		
60				5	60	100.00%		
72				6	72	100.00%		
84				7	84	100.00%		
96				8	96	100.00%		
108				9	108	100.00%		
120				10	120	100.00%		
132				11	132	100.00%		
144				12	144	100.00%		
156				13	156	100.00%		
168				14	168	100.00%		
180				15	180	100.00%		
192				16	192	100.00%		
204				17	204	100.00%		
216				18	216	100.00%		
228				19	228	100.00%		
240				20	240	100.00%		
252				21	252	100.00%		
264				22	264	100.00%		
276				23	276	100.00%		
288				24	288	100.00%		
300				25	300	100.00%		

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2020 Actual Incremental Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)	NG 4/1/22 - 5/24/2022 2023 (d)	PPL 5/25/22 - 12/31/22 2023 (e)	PPL 1/1/23 - 3/31/23 2023 (f)	9 months Calendar Year Dec-2023 (g)	12 months Calendar Year Dec-2024 (h)
	Capital Investment Allowance										
1	*Non-Discretionary Capital*			$32,485,802							
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$39,597,335							
3	Total Allowed Capital Included in Rate Base	Page 36 of 46, Line 4(c)		$72,083,137	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base										
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$72,083,137	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 36 of 46 , Line 10 ,Col (c)		$4,015,632	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$68,067,505	$68,067,505	$68,067,505	$68,067,505	$68,067,505	$68,067,505	$68,067,505	$68,067,505
	Change in Net Capital Included in Rate Base										
7	Capital Included in Rate Base	Line 3		$72,083,137	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 40 of 46, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$42,970,767	$42,970,767	$42,970,767	$42,970,767	$42,970,767	$42,970,767	$42,970,767	$42,970,767
10	Cost of Removal	Page 36 of 46 , Line 7 ,Col (c)		$10,949,557							
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**
	Deferred Tax Calculation:										
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/				54	221	90		
14	Proration Percentage		2/				14.79%	60.55%	24.66%	75.00%	
15	Vintage Year Tax Depreciation:										
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 13 of 46, Line 28, Then = Page 13 of 46, Column (d)		$23,811,948	$4,602,526	$4,256,970	$582,637	$2,489,534	$1,181,717	$3,610,802	$4,432,699
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$23,811,948	$28,414,474	$32,671,444	$33,254,080				
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/					$2,489,534	$3,671,252	$7,282,054	$11,714,753
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,075,467	$2,150,933	$2,150,933	$318,220	$1,302,346	$530,367	$1,613,200	$2,150,933
20	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$1,075,467	$3,226,400	$5,377,333	$5,695,553	$6,997,899	$7,528,266	$9,141,466	$11,292,399
21	Cumulative Book / Tax Timer	Columns (c) & (d): Line 17 - Line 20, Then Line 18 - Line 20		$22,736,481	$25,188,074	$27,294,111	$27,558,527	($4,508,365)	($3,857,014)	($1,859,412)	$422,354
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (d)	3/					$5,695,553	$5,695,553	$5,695,553	$5,695,553
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22						$1,187,189	$1,838,539	$3,836,141	$6,117,907
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (c) & (d): Line 21 * Line 24, Then Line 23 * Line 24		$4,774,661	$5,289,496	$5,731,763	$5,787,291	$249,310	$386,093	$805,590	$1,284,760
26	Add: FY 2020 Federal NOL Utilization	Page 36 of 46, Line 15, Col (c)	3/	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	$0	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$3,311,681	$3,826,515	$4,268,783	$4,324,310	$249,310	$386,093	$805,590	$1,284,760
	Rate Base Calculation:										
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$53,920,323	$53,920,323	$53,920,323	$53,920,323	$53,920,323	$53,920,323	$53,920,323	$53,920,323
29	Accumulated Depreciation	-Line 20		($1,075,467)	($3,226,400)	($5,377,333)	($5,695,553)	($6,997,899)	($7,528,266)	($9,141,466)	($11,292,399)
30	Deferred Tax Reserve	-Line 27		($3,311,681)	($3,826,515)	($4,268,783)	($4,324,310)	($249,310)	($386,093)	($805,590)	($1,284,760)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$49,533,176	$46,867,408	$44,274,208	$43,900,460	$46,673,115	$46,005,964	$43,973,268	$41,343,164
	Revenue Requirement Calculation:										
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 * Page 20 of 46, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$18,516,455	$48,200,292	$45,570,808	$45,140,086	$45,140,086	$45,140,086	$44,989,616	$42,658,216
33	Proration Adjustment	Columns (c) through (g) see Page 14 of 46, Line 41, Column (h) see Page 15 of 46, Line 41		$30,912	$18,700	$18,983	$18,955	$18,955	$18,955	$22,966	$19,420
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$18,547,368	$48,218,992	$45,589,791	$45,159,041	$45,159,041	$45,159,041	$45,012,582	$42,677,636
35	Pre-Tax ROR	Page 44 of 46, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/				14.79%	60.55%	24.66%	75.00%	
37	Return and Taxes	Cols (a) through (c) and (h): L 34 * L 35; Cols (d) through (g): L 34 * L 35 * L 36	2/	$1,526,448	$3,968,423	$3,752,040	$549,852	$2,250,318	$916,419	$2,778,402	$3,512,369
38	Book Depreciation	Line 19		$1,075,467	$2,150,933	$2,150,933	$318,220	$1,302,346	$530,367	$1,613,200	$2,150,933
39	**Annual Revenue Requirement**	Line 37 + Line 38		**$2,601,915**	**$6,119,356**	**$5,902,973**	**$868,072**	**$3,552,664**	**$1,446,786**	**$4,391,602**	**$5,663,303**
40	Docket No. 4915, FY 2020 Electric ISR Reconciliation, Page 9, Line 29										
41	2020 Tax True Up										

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))
2/ Columns (d) through (f) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (g) is prorated for the 9-month FY Dec. 2023 plan.
3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ Columns (d) through (f) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (c) and the end of the fiscal year on Line 31, Column (f). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2020 Incremental Capital Investments

Line No.				Fiscal Year 2020 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 12 of 46, Line 3		$72,083,137		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%					
3	Capital Repairs Deduction	Line 1 * Line 2		$6,134,275	NG MACRS basis:	Line 22, Column (a)		$63,755,733	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Proration	MACRS	Tax Depr
6	Plant Additions	Line 1		$72,083,137	FY Mar-2020	3.750%		$2,390,840	$23,811,948
7	Plant Additions			$0	FY Mar-2021	7.219%		$4,602,526	$28,414,474
8	Less Capital Repairs Deduction	Line 3		$6,134,275	FY Mar-2022	6.677%		$4,256,970	$32,671,444
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$65,948,862	FY Mar-2023 (Apr-May 2022)	6.177%	0.914%	$582,637	$33,254,081
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%					
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$65,948,862	PPL Acquisition - May 25, 2022				
12	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%	Book Cost	Line 1, Column (a)		$72,083,137	
13	Bonus Depreciation Rate	1 * 0% * 25%		0.00%	Cumulative Book Depreciation	- Page 12 of 46, Line 20, Col (d)		($5,695,553)	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		3.33%	PPL MACRS basis:	Line 12(e) + Line 13(e)		$66,387,584	
15	Bonus Depreciation	Line 11 * Line 14		$2,193,129					
16					FY Mar-2023 (Jun-Dec 2022)	3.750%		$2,489,534	$2,489,534
17	Remaining Tax Depreciation				FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$1,181,717	$3,671,252
18	Plant Additions	Line 1		$72,083,137	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$3,610,802	$7,282,054
19	Less Capital Repairs Deduction	Line 3		$6,134,275	CY 2024	6.677%		$4,432,699	$11,714,753
20	Less Bonus Depreciation	Line 15		$2,193,129	CY 2025	6.177%		$4,100,761	$15,815,514
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$63,755,733	CY 2026	5.713%		$3,792,723	$19,608,237
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	CY 2027	5.285%		$3,508,584	$23,116,821
23	Remaining Tax Depreciation	Line 21 * Line 22		$2,390,840	CY 2028	4.888%		$3,245,025	$26,361,846
24					CY 2029	4.522%		$3,002,047	$29,363,892
25	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147	CY 2030	4.462%		$2,962,214	$32,326,106
26	Cost of Removal	Page 12 of 46, Line 10		$10,949,557	CY 2031	4.461%		$2,961,550	$35,287,656
27					CY 2032	4.462%		$2,962,214	$38,249,870
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$23,811,948	CY 2033	4.461%		$2,961,550	$41,211,420
29					CY 2034	4.462%		$2,962,214	$44,173,634
30					CY 2035	4.461%		$2,961,550	$47,135,184
31					CY 2036	4.462%		$2,962,214	$50,097,398
32					CY 2037	4.461%		$2,961,550	$53,058,949
33					CY 2038	4.462%		$2,962,214	$56,021,163
34					CY 2039	4.461%		$2,961,550	$58,982,713
35					CY 2040	4.462%		$2,962,214	$61,944,927
36					CY 2041	4.461%		$2,961,550	$64,906,477
37					CY 2042	2.231%		$1,481,107	$66,387,584
38						100.00%		$66,387,584	

1/ Per Tax Department
2/ Per Tax Department
3/ Per Tax Department
Column (d), Line 9 = MACRS Rate 6.177% / 365 days x 54 days
Column (d), Line 17 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 18 = MACRS Rate 7.219% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 12 of 46, Line 19, column (c); Col (b): Page 12 of 46, Line 19, columns (d) through (f); Col (c): Page 12 of 46, Line 19, column (g)	$2,150,933	$2,150,933	$1,613,200
2	Bonus Depreciation		$0		$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 13 of 46, Line 8, column, (e); Col (b): - Page 13 of 46, Sum of Lines 9,16,17, column, (e); Col (c): - Page 13 of 46, Line 18, column, (e)	($4,256,970)	($4,253,888)	($3,610,802)
4	FY 2020 tax (gain)/loss on retirements	Year 1 = Docket No. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,106,037)	($2,102,955)	($1,997,603)
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($442,268)	($441,621)	($419,497)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
9	Cost of Removal	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
10	Book/Tax Depreciation Timing Difference at 3/31/2020				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($442,268)	($441,621)	($419,497)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($442,268)	($441,621)	($419,497)
	Allocation of FY 2020 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5	($2,106,037)	($2,102,955)	($1,997,603)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($2,106,037)	($2,102,955)	($1,997,603)
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0	$0	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($442,268)	($441,621)	($419,497)

Line No.	Proration Calculation	Number of Days in Month (d)	Proration Percentage (e)	FY22 (f)	FY23-NG (g)	Apr 1 - Dec 31 2023 (h)
26	April	30	91.78%	($33,826)	($33,777)	($41,526)
27	May	31	83.29%	($30,696)	($30,651)	($36,272)
28	June	30	75.07%	($27,667)	($27,626)	($31,187)
29	July	31	66.58%	($24,537)	($24,501)	($25,933)
30	August	31	58.08%	($21,407)	($21,375)	($20,678)
31	September	30	49.86%	($18,377)	($18,350)	($15,593)
32	October	31	41.37%	($15,247)	($15,225)	($10,339)
33	November	30	33.15%	($12,218)	($12,200)	($5,254)
34	December	31	24.66%	($9,088)	($9,074)	
35	January	31	16.16%	($5,957)	($5,949)	
36	February	28	8.49%	($3,130)	($3,126)	
37	March	31	0.00%	$0	$0	
38	Total	365		($202,151)	($201,855)	($186,782)
39	Deferred Tax Without Proration	Line 25		($442,268)	($441,621)	($419,497)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 20 of 46, Line 16, Col (e); then = Line 39 * 50%		($221,134)	($220,810)	($209,748)
41	Proration Adjustment	Line 38 - Line 40		$18,983	$18,955	$22,966

Column Notes:

(e)	Sum of remaining days in the year (Col (d)) ÷ 365
(f) & (g)	Current Year Line 25 ÷ 12 × Current Month Col (e)
(h)	Current Year Line 25 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (d)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment Post CY 2023

Line No.			CY24 (a)
	Deferred Tax Subject to Proration		
1	Book Depreciation	Page 12 of 46, Line 19, column (h)	$2,150,933
2	Bonus Depreciation		$0
3	Remaining MACRS Tax Depreciation	Page 13 of 46, Line 19, col (e)	($4,432,699)
4	FY 2020 tax (gain)/loss on retirements	Year 1 = Docket No. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,281,766)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($479,171)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
9	Cost of Removal	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
10	Book/Tax Depreciation Timing Difference at 3/31/2020		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($479,171)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($479,171)
	Allocation of FY 2020 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5	($2,281,766)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($2,281,766)
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($479,171)

		(b)	(c)	(d)
	Proration Calculation	Number of Days in Month	Proration Percentage	CY24
26	January	31	91.53%	($36,549)
27	February	29	83.61%	($33,385)
28	March	31	75.14%	($30,003)
29	April	30	66.94%	($26,730)
30	May	31	58.47%	($23,348)
31	June	30	50.27%	($20,075)
32	July	31	41.80%	($16,692)
33	August	31	33.33%	($13,310)
34	September	30	25.14%	($10,037)
35	October	31	16.67%	($6,655)
36	November	30	8.47%	($3,382)
37	December	31	0.00%	$0
38	Total	366		($220,165)
39	Deferred Tax Without Proration	Line 25		($479,171)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 20 of 46, Line 16, Col (e); then = Line 39 * 50%		($239,585)
41	Proration Adjustment	Line 38 - Line 40		$19,420

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 27 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Dec-24 Revenue Requirement on FY 2021 Forecasted Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	NG Fiscal Year 2022 (b)	NG 4/1/22 - 5/24/2022 2023 (c)	PPL 5/25/22 - 12/31/22 2023 (d)	PPL 1/1/23 - 3/31/23 2023 (e)	9 months Calendar Year Dec-2023 (f)	12 months Calendar Year Dec-2024 (g)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*			$36,445,546						
	Discretionary Capital									
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)			$80,041,254						
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 36 of 46, Line 4(d)		$116,486,800	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base									
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$116,486,800	$0	$0	$0	$0	$0	$0
5	Retirements	Page 36 of 46 , Line 10 ,Col (d)		$21,996,026	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$94,490,774	$94,490,774	$94,490,774	$94,490,774	$94,490,774	$94,490,774	$94,490,774
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3		$116,486,800	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 40 of 46, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$66,579,879	$66,579,879	$66,579,879	$66,579,879	$66,579,879	$66,579,879	$66,579,879
10	Cost of Removal	Page 36 of 46 , Line 7 ,Col (d)		$11,093,804						
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$77,673,683**	**$77,673,683**	**$77,673,683**	**$77,673,683**	**$77,673,683**	**$77,673,683**	**$77,673,683**
	Deferred Tax Calculation:									
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/			54	221	90		
14	Proration Percentage		2/			14.79%	60.55%	24.66%	75.00%	
15	Vintage Year Tax Depreciation:									
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 17 of 46, Line 28, Column (a), Then = Line Page 17 of 46 , Column (d)		$45,333,033	$6,434,279	$880,451	$4,183,732	$1,985,909	$6,068,054	$7,449,274
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$45,333,033	$51,767,312	$52,647,763				
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/				$4,183,732	$6,169,641	$12,237,695	$19,686,969
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,492,954	$2,985,908	$441,751	$1,807,906	$736,251	$2,239,431	$2,985,908
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$1,492,954	$4,478,863	$4,920,614	$6,728,520	$7,464,771	$9,704,202	$12,690,111
21	Cumulative Book / Tax Timer	Columns (a) through (c): Line 17 - Line 20, Then Line 18 - Line 20		$43,840,079	$47,288,450	$47,727,150	($2,544,788)	($1,295,130)	$2,533,493	$6,996,858
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (c)	3/				$4,920,614	$4,920,614	$4,920,614	$4,920,614
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$2,375,826	$3,625,483	$7,454,106	$11,917,472
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (c): Line 21 * Line 24, Then Line 23 * Line 24		$9,206,417	$9,930,574	$10,022,701	$498,923	$761,351	$1,565,362	$2,502,669
26	Add: FY 2021 Federal (NOL) Utilization	Page 36 of 46, Line 15, Col (d)	3/	($5,639,147)	($5,639,147)	($5,639,147)	$0	$0	$0	$0
27	Net Deferred Tax Reserve beforee Proration Adjustment	Sum of Lines 25 through 26		$3,567,269	$4,291,427	$4,383,554	$498,923	$761,351	$1,565,362	$2,502,669
	Rate Base Calculation:									
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$77,673,683	$77,673,683	$77,673,683	$77,673,683	$77,673,683	$77,673,683	$77,673,683
29	Accumulated Depreciation	-Line 20		($1,492,954)	($4,478,863)	($4,920,614)	($6,728,520)	($7,464,771)	($9,704,202)	($12,690,111)
30	Deferred Tax Reserve	-Line 27		($3,567,269)	($4,291,427)	($4,383,554)	($498,923)	($761,351)	($1,565,362)	($2,502,669)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$72,613,460	$68,903,394	$68,369,516	$70,446,240	$69,447,561	$66,404,118	$62,480,903
	Revenue Requirement Calculation:									
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$36,306,730	$70,758,427	$69,175,477	$69,175,477	$69,175,477	$67,925,840	$64,442,511
33	Proration Adjustment	Columns (a) through (f) see Page 18 of 46, Line 41; Column (g) see Page 19 of 46, Line 41		$16,670	$31,083	$36,633	$36,633	$36,633	$44,018	$37,987
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$36,323,400	$70,789,509	$69,212,110	$69,212,110	$69,212,110	$67,969,857	$64,480,498
35	Pre-Tax ROR	Page 44 of 46, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/			14.79%	60.55%	24.66%	75.00%	
37	Return and Taxes	Cols (a),(b) and (f): L 34 * L 35; Cols (c) through (f): L 34 * L 35 * L 36	2/	$2,989,416	$5,825,977	$842,719	$3,448,906	$1,404,532	$4,195,439	$5,306,745
38	Book Depreciation	Line 19		$1,492,954	$2,985,908	$441,751	$1,807,906	$736,251	$2,239,431	$2,985,908
39	Revenue Requirement of Intangible Assets									
40	**Annual Revenue Requirement**	**Line 37 + Line 38 + Line 39**		**$4,482,370**	**$8,811,885**	**$1,284,470**	**$5,256,812**	**$2,140,783**	**$6,434,871**	**$8,292,653**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))
2/ Columns (c) through (e) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (f) is prorated for the 9-month FY Dec. 2023 plan.
3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ Columns (c) through (e) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (b) and the end of the fiscal year on Line 31, Column (e). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 16 of 46, Line 3(a)		$116,486,800
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%
3	Capital Repairs Deduction	Line 1 * Line 2		$27,357,013
4				
5	Bonus Depreciation			
6	Plant Additions	Line 1		$116,486,800
7	Plant Additions			$0
8	Less Capital Repairs Deduction	Line 3		$27,357,013
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$89,129,787
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0
12	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%
13	Bonus Depreciation Rate	1 * 25% * 0%		0.00%
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%
15	Bonus Depreciation	Line 11 * Line 14		$0
16				
17	Remaining Tax Depreciation			
18	Plant Additions	Line 1		$116,486,800
19	Less Capital Repairs Deduction	Line 3		$27,357,013
20	Less Bonus Depreciation	Line 15		$0
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$89,129,787
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
23	Remaining Tax Depreciation	Line 21 * Line 22		$3,342,367
24				
25	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$3,539,849
26	Cost of Removal	Page 16 of 46, Line 10		$11,093,804
27				
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$45,333,033

Line No.	(b)	(c)	(d)	(e)	(f)
1	20 Year MACRS Depreciation				
2					
3	MACRS basis:	Line 21, Column (a)		$89,129,787	
4				Annual	Cumulative
5	Fiscal Year		Prorated	MACRS	Tax Depr
6	FY Mar-2021	3.750%		$3,342,367	$45,333,033
7	FY Mar-2022	7.219%		$6,434,279	$51,767,312
8	FY Mar-2023 (Apr-May 2022)	6.677%	0.988%	$880,451	$52,647,763
9					
10	PPL Acquisition - May 25, 2022				
11	Book Cost	Line 1, Column (a)		$116,486,800	
12	Cumulative Book Depreciation	- Page 16 of 46, Line 20, Col (c)		($4,920,614)	
13	PPL MACRS basis:	Line 11(e) + Line 12(e)		$111,566,186	
14					
15	FY Mar-2023 (Jun-Dec 2022)	3.750%		$4,183,732	$4,183,732
16	FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$1,985,909	$6,169,641
17	CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$6,068,054	$12,237,695
18	CY 2024	6.677%		$7,449,274	$19,686,969
19	CY 2025	6.177%		$6,891,443	$26,578,413
20	CY 2026	5.713%		$6,373,776	$32,952,189
21	CY 2027	5.285%		$5,896,273	$38,848,462
22	CY 2028	4.888%		$5,453,355	$44,301,817
23	CY 2029	4.522%		$5,045,023	$49,346,840
24	CY 2030	4.462%		$4,978,083	$54,324,923
25	CY 2031	4.461%		$4,976,968	$59,301,891
26	CY 2032	4.462%		$4,978,083	$64,279,974
27	CY 2033	4.461%		$4,976,968	$69,256,941
28	CY 2034	4.462%		$4,978,083	$74,235,025
29	CY 2035	4.461%		$4,976,968	$79,211,992
30	CY 2036	4.462%		$4,978,083	$84,190,076
31	CY 2037	4.461%		$4,976,968	$89,167,043
32	CY 2038	4.462%		$4,978,083	$94,145,126
33	CY 2039	4.461%		$4,976,968	$99,122,094
34	CY 2040	4.462%		$4,978,083	$104,100,177
35	CY 2041	4.461%		$4,976,968	$109,077,145
36	CY 2042	2.231%		$2,489,042	$111,566,186
37		100.00%		$111,566,186	

1/ Per Tax Department
2/ Per Tax Department
Column (d), Line 8 = MACRS Rate 6.677% / 365 days x 54 days
Column (d), Line 16 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 17 = MACRS Rate 7.219% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment Pre CY 2024

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 16 of 46, Line 19, column (b); Col (b): Page 16 of 46, Line 19, columns (c) through (e); Col (c): Page 16 of 46, Line 19, column (f)	$2,985,908	$2,985,908	$2,239,431
2	Bonus Depreciation	Page 17 of 46, Line 20	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 17 of 46, Line 8, column, (e); Col (b): Page 17 of 46, Sum of Lines 8,15,16, column, (e); Col (c): - Page 17 of 46, Line 17, column, (e)	($6,434,279)	($7,050,092)	($6,068,054)
4	FY 2021 tax (gain)/loss on retirements	- Page 17 of 46, Line 25			
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,448,371)	($4,064,183)	($3,828,623)
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($724,158)	($853,478)	($804,011)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 17 of 46, Line 3			
9	Cost of Removal	- Page 17 of 46, Line 26			
10	Book/Tax Depreciation Timing Difference at 3/31/2021				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12		$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($724,158)	($853,478)	($804,011)
15	Net Operating Loss	Page 16 of 46, Line 26	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($724,158)	($853,478)	($804,011)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,448,371)	($4,064,183)	($3,828,623)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($3,448,371)	($4,064,183)	($3,828,623)
20	Total FY 2021 Federal NOL (Utilization)	- Page 16 of 46, Line 26 / 21%	$0	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($724,158)	($853,478)	($804,011)

		(d)	(e)	(f)	(g)	(h)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23-NG	Apr 1 - Dec 31 2023
26	April	30	91.78%	($55,387)	($65,277)	($79,589)
27	May	31	83.29%	($50,261)	($59,237)	($69,519)
28	June	30	75.07%	($45,301)	($53,391)	($59,773)
29	July	31	66.58%	($40,176)	($47,351)	($49,702)
30	August	31	58.08%	($35,051)	($41,310)	($39,632)
31	September	30	49.86%	($30,091)	($35,464)	($29,886)
32	October	31	41.37%	($24,965)	($29,424)	($19,816)
33	November	30	33.15%	($20,005)	($23,578)	($10,070)
34	December	31	24.66%	($14,880)	($17,537)	
35	January	31	16.16%	($9,755)	($11,497)	
36	February	28	8.49%	($5,125)	($6,041)	
37	March	31	0.00%	$0	$0	
38	Total	365		($330,996)	($390,106)	($357,988)
39	Deferred Tax Without Proration	Line 25		($724,158)	($853,478)	($804,011)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($362,079)	($426,739)	($402,005)
41	Proration Adjustment	Line 38 - Line 40		$31,083	$36,633	$44,018

Column Notes:

(e)	Sum of remaining days in the year (Col (d)) ÷ 365
(f) through (g)	Current Year Line 25 ÷ 12 × Current Month Col (e)
(h)	Current Year Line 25 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (d)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration		CY24 (a)	CY25
1	Book Depreciation	Page 16 of 46, Line 19, Column (g)	$2,985,908	$2,985,908
2	Bonus Depreciation	Page 17 of 46, Line 20	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 17 of 46, Line 18, column (e)	($7,449,274)	($6,891,443)
4	FY 2021 tax (gain)/loss on retirements	- Page 17 of 46, Line 25		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($4,463,366)	($3,905,535)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($937,307)	($820,162)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 17 of 46, Line 3		
9	Cost of Removal	- Page 17 of 46, Line 26		
10	Book/Tax Depreciation Timing Difference at 3/31/2021			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	
14	Total Deferred Tax Reserve	Line 7 + Line 13	($937,307)	($820,162)
15	Net Operating Loss	Page 16 of 46, Line 26	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($937,307)	($820,162)
	Allocation of FY 2021 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($4,463,366)	($3,905,535)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($4,463,366)	($3,905,535)
20	Total FY 2021 Federal NOL (Utilization)	- Page 16 of 46, Line 26 / 0%	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($937,307)	($820,162)

Line No.	Proration Calculation	(b) Number of Days in Month	(c) Proration Percentage	(d) CY24	CY25
26	January	31	91.53%	($71,493)	($62,558)
27	February	29	83.61%	($65,304)	($57,142)
28	March	31	75.14%	($58,688)	($51,354)
29	April	30	66.94%	($52,286)	($45,751)
30	May	31	58.47%	($45,670)	($39,962)
31	June	30	50.27%	($39,268)	($34,360)
32	July	31	41.80%	($32,652)	($28,571)
33	August	31	33.33%	($26,036)	($22,782)
34	September	30	25.14%	($19,634)	($17,180)
35	October	31	16.67%	($13,018)	($11,391)
36	November	30	8.47%	($6,616)	($5,789)
37	December	31	0.00%	$0	$0
38	Total	366		($430,666)	($376,841)
39	Deferred Tax Without Proration	Line 25		($937,307)	($820,162)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($468,653)	($410,081)
41	Proration Adjustment	Line 38 - Line 40		$37,987	$33,240

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 25 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
ISR Additions April 2020 through March 2021

Line No.	Month No.	Month	FY 2021 Plant Additions (a)	In Rates (b)	Not In Rates (c) = (a) - (b)	Weight for Days (d)	Weighted Average (e) = (d) * (c)	Weight for Not in Rates (f)=(c)/Total(c)
1								
2	1	Apr-20	8,605,643	6,236,917	2,368,727	0.958	2,270,030	3.29%
3	2	May-20	8,605,643	6,236,917	2,368,727	0.875	2,072,636	3.29%
4	3	Jun-20	8,605,643	6,236,917	2,368,727	0.792	1,875,242	3.29%
5	4	Jul-20	8,605,643	6,236,917	2,368,727	0.708	1,677,848	3.29%
6	5	Aug-20	8,605,643	6,236,917	2,368,727	0.625	1,480,454	3.29%
7	6	Sep-20	8,605,643	-	8,605,643	0.542	4,661,390	11.94%
8	7	Oct-20	8,605,643	-	8,605,643	0.458	3,944,253	11.94%
9	8	Nov-20	8,605,643	-	8,605,643	0.375	3,227,116	11.94%
10	9	Dec-20	8,605,643	-	8,605,643	0.292	2,509,979	11.94%
11	10	Jan-21	8,605,643	-	8,605,643	0.208	1,792,842	11.94%
12	11	Feb-21	8,605,643	-	8,605,643	0.125	1,075,705	11.94%
13	12	Mar-21	8,605,643	-	8,605,643	0.042	358,568	11.94%
14		Total	$103,267,720	$31,184,583	$72,083,137		$26,946,065	100.00%
15	**Total September 2020 through March 2021**			**$**	**60,239,503**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**						**37.38%**	

Column (a)=Page 36 of 46, Line 1(c)
Column(b)=Page 36 of 46, Line 2(c)
Line 15 = sum of Line 7(c) through Line 13(c)
Line 16 = Line 14(f)/Line 14(c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2022 Forecasted Incremental Capital Investment

Line No.				Fiscal Year 2022 (a)	NG 4/1/22 - 5/24/2022 2023 (b)	PPL 5/25/22 - 12/31/22 2023 (c)	PPL 1/1/23 - 3/31/23 2023 (d)	9 months Calendar Year Dec-2023 (e)	12 months Calendar Year Dec-2024 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*	Docket 5098, P 29 of 29. Line 1(a)		$46,562,272					
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Docket 5098, P 29 of 29. Line 2(a)		$42,200,430				$0	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 36 of 46, Line 4(e)		$88,762,702	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base								
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$88,762,702	$0	$0	$0	$0	$0
5	Retirements	Page 36 of 46 , Line 10 ,Col (e)		$34,853,004	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$53,909,698	$53,909,698	$53,909,698	$53,909,698	$53,909,698	$53,909,698
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$88,762,702	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 40 of 46, Line 62, Col (d)		$49,906,920	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$38,855,782	$38,855,782	$38,855,782	$38,855,782	$38,855,782	$38,855,782
10	Cost of Removal	Page 36 of 46 , Line 7 ,Col (e)		$7,658,876	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$46,514,657**	**$46,514,657**	**$46,514,657**	**$46,514,657**	**$46,514,657**	**$46,514,657**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/		54	221	90		
14	Proration Percentage		2/		14.79%	60.55%	24.66%	75.00%	
15	Vintage Year Tax Depreciation:								
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 22 of 46, Line 27, Column (a), Then = Line Page 22 of 46 , Column (d)		$20,402,066	$867,325	$3,287,209	$1,560,352	$4,767,743	$5,852,985
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$20,402,066	$21,269,391				
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/			$3,287,209	$4,847,561	$9,615,304	$15,468,289
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line		$851,773	$252,032	$1,031,462	$420,053	$1,277,660	$1,703,546
20	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$851,773	$1,103,805	$2,135,267	$2,555,320	$3,832,980	$5,536,526
21	Cumulative Book / Tax Timer	Columns (a) & (b): Line 17 - Line 20, Then Line 18 - Line 20		$19,550,292	$20,165,586	$1,151,942	$2,292,241	$5,782,325	$9,931,763
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (b)	3/			$1,103,805	$1,103,805	$1,103,805	$1,103,805
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22				$2,255,746	$3,396,046	$6,886,130	$11,035,568
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Line 21 * Line 24		$4,105,561	$4,234,773	$473,707	$713,170	$1,446,087	$2,317,469
26	Add: FY 2022 Federal (NOL) Utilization	Page 36 of 46, Line 15, Col (e)	3/	$1,703,802	$1,703,802	$0	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 25 through 26		$5,809,364	$5,938,575	$473,707	$713,170	$1,446,087	$2,317,469
	Rate Base Calculation:								
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$46,514,657	$46,514,657	$46,514,657	$46,514,657	$46,514,657	$46,514,657
29	Accumulated Depreciation	-Line 20		($851,773)	($1,103,805)	($2,135,267)	($2,555,320)	($3,832,980)	($5,536,526)
30	Deferred Tax Reserve	-Line 27		($5,809,364)	($5,938,575)	($473,707)	($713,170)	($1,446,087)	($2,317,469)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$39,853,520	$39,472,277	$43,905,683	$43,246,168	$41,235,590	$38,660,662
	Revenue Requirement Calculation:								
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$19,926,760	$41,549,844	$41,549,844	$41,549,844	$42,240,879	$39,948,126
33	Proration Adjustment	Columns (a) through (e) see Page 23 of 46, Line 41; Column (f) see Page 24 of 46, Line 41		$19,772	$36,157	$36,157	$36,157	$40,125	$35,316
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$19,946,532	$41,586,001	$41,586,001	$41,586,001	$42,281,005	$39,983,442
35	Pre-Tax ROR	Page 44 of 46, Line 33		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/		14.79%	60.55%	24.66%	75.00%	
37	Return and Taxes	Col (a) and (f): L 34 * L 35; Cols (b) through (e): L 34 * L 35 * L 36	2/	$1,641,600	$506,347	$2,072,270	$843,911	$2,609,795	$3,290,637
38	Book Depreciation	Line 19		$851,773	$252,032	$1,031,462	$420,053	$1,277,660	$1,703,546
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$2,493,373**	**$758,378**	**$3,103,733**	**$1,263,964**	**$3,887,455**	**$4,994,184**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))
2/ Columns (b) through (d) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (e) is prorated for the 9-month FY Dec. 2023 plan.
3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ Columns (b) through (d) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 31, Column (a) and the end of the fiscal year on Line 31, Column (d). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2022 Incremental Capital Investments

Line No.				Fiscal Year 2022 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 21 of 46, Line 3		$88,762,702		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%					
3	Capital Repairs Deduction	Line 1 * Line 2		$7,553,706	NG MACRS basis:	Line 22, Column (a)		$81,208,996	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$88,762,702	FY Mar-2022	3.750%		$3,045,337	$20,402,066
7	Plant Additions			$0	FY Mar-2023 (Apr-May 2022)	7.219%	1.068%	$867,325	$21,269,391
8	Less Capital Repairs Deduction	Line 3		$7,553,706					
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$81,208,996	PPL Acquisition - May 25, 2022				
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Book Cost	Line 1, Column (a)		$88,762,702	
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Cumulative Book Depreciation	- Page 21 of 46, Line 20, Col (b)		($1,103,805)	
12	Bonus Depreciation Rate	at 0%		0.00%	PPL MACRS basis:	Line 10(e) + Line 11(e)		$87,658,897	
13	Total Bonus Depreciation Rate	Line 12		0.00%					
14	Bonus Depreciation	Line 11 * Line 13		$0	FY Mar-2023 (Jun-Dec 2022)	3.750%		$3,287,209	$3,287,209
15					FY Mar-2023 (Jan-Mar 2023)	7.219%	1.780%	$1,560,352	$4,847,561
16	Remaining Tax Depreciation				CY 2023 (Apr-Dec 2023)	7.219%	5.439%	$4,767,743	$9,615,304
17	Plant Additions	Line 1		$88,762,702	CY 2024	6.677%		$5,852,985	$15,468,289
18	Less Capital Repairs Deduction	Line 3		$7,553,706	CY 2025	6.177%		$5,414,690	$20,882,979
19	Less Bonus Depreciation	Line 14		$0	CY 2026	5.713%		$5,007,953	$25,890,932
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$81,208,996	CY 2027	5.285%		$4,632,773	$30,523,705
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	CY 2028	4.888%		$4,284,767	$34,808,472
22	Remaining Tax Depreciation	Line 20 * Line 21		$3,045,337	CY 2029	4.522%		$3,963,935	$38,772,407
23					CY 2030	4.462%		$3,911,340	$42,683,747
24	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$2,144,147	CY 2031	4.461%		$3,910,463	$46,594,210
25	Cost of Removal	Page 21 of 46, Line 10		$7,658,876	CY 2032	4.462%		$3,911,340	$50,505,550
26					CY 2033	4.461%		$3,910,463	$54,416,014
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$20,402,066	CY 2034	4.462%		$3,911,340	$58,327,354
28					CY 2035	4.461%		$3,910,463	$62,237,817
29					CY 2036	4.462%		$3,911,340	$66,149,157
30					CY 2037	4.461%		$3,910,463	$70,059,620
31					CY 2038	4.462%		$3,911,340	$73,970,960
32					CY 2039	4.461%		$3,910,463	$77,881,424
33					CY 2040	4.462%		$3,911,340	$81,792,764
34					CY 2041	4.461%		$3,910,463	$85,703,227
35					CY 2042	2.231%		$1,955,670	$87,658,897
36						100.00%		$87,658,897	

1/ Per Tax Department
2/ Per Tax Department
Column (d), Line 7 = MACRS Rate 6.677% / 365 days x 54 days
Column (d), Line 15 = MACRS Rate 7.219% / 365 days x 90 days
Column (d), Line 16 = MACRS Rate 7.219% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment Pre CY 2024

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23-NG (b)	Apr 1 - Dec 31 2023 (c)
1	Book Depreciation	Col (a): Page 21 of 46, Line 19, column (a); Col (b): Page 21 of 46, Line 19, columns (b) through (d); Col (c): Page 21 of 46, Line 19, column (e)	$851,773	$1,703,546	$1,277,660
2	Bonus Depreciation	Page 17 of 46, Line 20	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 22 of 46, Line 6, column, (e); Col (b): - Page 22 of 46, Sum of Lines 7,14,15, column, (e); Col (c): - Page 22 of 46, Line 16, column, (e)	($3,045,337)	($5,714,886)	($4,767,743)
4	FY 2022 tax (gain)/loss on retirements	- Page 22 of 46, Line 24			
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,193,564)	($4,011,340)	($3,490,084)
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($460,648)	($842,381)	($732,918)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 22 of 46, Line 3			
9	Cost of Removal	- Page 22 of 46, Line 25			
10	Book/Tax Depreciation Timing Difference at 3/31/2022				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($460,648)	($842,381)	($732,918)
15	Net Operating Loss	Page 21 of 46, Line 26	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($460,648)	($842,381)	($732,918)
	Allocation of FY 2022 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($2,193,564)	($4,011,340)	($3,490,084)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($2,193,564)	($4,011,340)	($3,490,084)
20	Total FY 2022 Federal NOL (Utilization)	- Page 21 of 46, Line 26 / 21%	$0	$0	$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($460,648)	($842,381)	($732,918)

Line No.	Proration Calculation	Number of Days in Month (d)	Proration Percentage (e)	FY22 (f)	FY23-NG (g)	Apr 1 - Dec 31 2023 (h)
26	April	30	91.78%	($35,232)	($64,429)	($72,551)
27	May	31	83.29%	($31,972)	($58,467)	($63,371)
28	June	30	75.07%	($28,817)	($52,697)	($54,488)
29	July	31	66.58%	($25,557)	($46,735)	($45,308)
30	August	31	58.08%	($22,296)	($40,773)	($36,128)
31	September	30	49.86%	($19,141)	($35,003)	($27,244)
32	October	31	41.37%	($15,881)	($29,041)	($18,064)
33	November	30	33.15%	($12,726)	($23,271)	($9,180)
34	December	31	24.66%	($9,465)	($17,309)	
35	January	31	16.16%	($6,205)	($11,347)	
36	February	28	8.49%	($3,260)	($5,962)	
37	March	31	0.00%	$0	$0	
38	Total	365		($210,552)	($385,034)	($326,333)
39	Deferred Tax Without Proration	Line 25		($460,648)	($842,381)	($732,918)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($230,324)	($421,191)	($366,459)
41	Proration Adjustment	Line 38 - Line 40		$19,772	$36,157	$40,125

Column Notes:

(e) Sum of remaining days in the year (Col (d)) ÷ 365
(f) through (g) Current Year Line 25 ÷ 12 × Current Month Col (e)
(h) Current Year Line 25 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (d)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment Post CY 2023

Line No.	**Deferred Tax Subject to Proration**		CY24 (a)
1	Book Depreciation	Page 21 of 46, Line 19, Column (f)	$1,703,546
2	Bonus Depreciation	Page 17 of 46, Line 20	$0
3	Remaining MACRS Tax Depreciation	- Page 22 of 46, Line 17, column (e)	($5,852,985)
4	FY 2022 tax (gain)/loss on retirements	- Page 22 of 46, Line 24	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($4,149,438)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($871,382)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 22 of 46, Line 3	
9	Cost of Removal	- Page 22 of 46, Line 25	
10	Book/Tax Depreciation Timing Difference at 3/31/2022		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($871,382)
15	Net Operating Loss	Page 21 of 46, Line 26	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($871,382)
	Allocation of FY 2022 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($4,149,438)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($4,149,438)
20	Total FY 2022 Federal NOL (Utilization)	- Page 21 of 46, Line 26 / 0%	$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($871,382)

Line No.	**Proration Calculation**	(b) Number of Days in Month	(c) Proration Percentage	(d) CY24
26	January	31	91.53%	($66,465)
27	February	29	83.61%	($60,711)
28	March	31	75.14%	($54,561)
29	April	30	66.94%	($48,609)
30	May	31	58.47%	($42,458)
31	June	30	50.27%	($36,506)
32	July	31	41.80%	($30,356)
33	August	31	33.33%	($24,205)
34	September	30	25.14%	($18,253)
35	October	31	16.67%	($12,103)
36	November	30	8.47%	($6,150)
37	December	31	0.00%	$0
38	Total	366		($400,375)
39	Deferred Tax Without Proration	Line 25		($871,382)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($435,691)
41	Proration Adjustment	Line 38 - Line 40		$35,316

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 25 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on FY 2023-NG Forecasted Incremental Capital Investment

Line No.				NG 4/1/22 - 5/24/2022 2023 (a)	PPL 5/25/22 - 12/31/22 2023 (b)	PPL 1/1/23 - 3/31/23 2023 (c)	Total Fiscal Year 2023 (d)	9 months Calendar Year Dec-2023 (e)	12 months Calendar Year Dec-2024 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*	Docket 5209, P 33 of 33. Line 1		$6,378,510	$26,104,641	$10,630,849	$43,114,000		
	Discretionary Capital								
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Docket 5209, P 33 of 33. Line 13		$9,194,795	$37,630,548	$15,324,658	$62,150,000		
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$15,573,304	$63,735,189	$25,955,507	$105,264,000	$0	$0
	Depreciable Net Capital Included in Rate Base								
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$15,573,304	$63,735,189	$25,955,507	$105,264,000		
5	Retirements	Company's Record		$2,257,923	$9,240,760	$3,763,205	$15,261,889		
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$13,315,381	$54,494,429	$22,192,301	$90,002,111	$90,002,111	$90,002,111
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$15,573,304	$63,735,189	$25,955,507	$105,264,000		
8	Depreciation Expense	Page 40 of 46, Line 62, Col (d)		$7,383,490	$30,217,615	$12,305,816	$49,906,920		
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$8,189,815	$33,517,574	$13,649,691	$55,357,080	$55,357,080	$55,357,080
10	Cost of Removal	Company's Record		$2,411,507	$9,869,315	$4,019,178	$16,300,000		
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$10,601,321**	**$43,386,889**	**$17,668,869**	**$71,657,080**	**$71,657,080**	**$71,657,080**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Proration Percentage		2/					75.00%	
14	Vintage Year Tax Depreciation:								
15	Tax Depreciation and Year 1 Basis Adjustments	Col (a) = Page 26 of 46, Column (a), Line 27; Col (b) = Page 26 of 46, Col (b), Lines 18,24,25 + Col (i), Line 18; Col (c) = Page 26 of 46, Col (c), Lines 18,24,25 + Col (i), Line 19, Then remaining years from Page 26 of 46, Col (i)		$6,534,245	$27,318,112	$11,470,829	$45,323,185	$4,049,117	$5,715,636
16	Cumulative Tax Depreciation-NG	Year 1 = Line 15; then = Prior Year Line 16 + Current Year Line 15	3/				$6,534,245		
17	Cumulative Tax Depreciation-PPL	Year 1 = Line 15; then = Prior Year Line 17 + Current Year Line 15	3/				$38,788,941	$42,838,058	$48,553,694
18	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$210,383	$861,012	$350,638	$1,422,033	$2,133,050	$2,844,067
19	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16					$1,422,033	$3,555,083	$6,399,150
20	Cumulative Book / Tax Timer	Columns (a),(b) & (c): Line 15 - Line 18, Then Line 17 - Line 19		$6,323,862	$26,457,100	$11,120,191	$43,901,152	$1,916,067	$2,871,570
21	Less: Cumulative Book Depreciation at Acquisition	Line 19 Column (a)	3/				$6,323,862		
22	Cumulative Book / Tax Timer - PPL	Line 20, Columns (b) and (c), then = Prior Year Line 22 + Current Year Line 20					$37,577,290	$39,493,357	$42,364,927
23	Cumulative Book / Tax Timer - Total	Line 21 + Line 22					$43,901,152	$39,493,357	$42,364,927
24	Effective Tax Rate						21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Line 23 × Line 24					$9,219,242	$8,293,605	$8,896,635
26	Add: FY 2023 Federal (NOL) Utilization	Page 36 of 46 , Line 13 ,Col (f)	3/				($43,783)	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26					$9,175,459	$8,293,605	$8,896,635
	Rate Base Calculation:								
28	Cumulative Incremental Capital Included in Rate Base	Line 11					$71,657,080	$71,657,080	$71,657,080
29	Accumulated Depreciation	-Line 19					($1,422,033)	($3,555,083)	($6,399,150)
30	Deferred Tax Reserve	-Line 27					($9,175,459)	($8,293,605)	($8,896,635)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30					$61,059,587	$59,808,391	$56,361,295
	Revenue Requirement Calculation:								
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2	4/				$30,529,794	$60,433,989	$58,084,843
33	Proration Adjustment	Page 27 of 46, Line 41					$25,959	$22,029	$24,440
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34					$30,555,752	$60,456,018	$58,109,283
35	Pre-Tax ROR	Page 44 of 46, Line 33					8.23%	8.23%	8.23%
36	Proration	Line 13	2/					75.00%	
37	Return and Taxes	Cols (a) through (c) and (f) : L 34 * L 35; Col (e): L 34 * L 35 * L 36	2/				$2,514,738	$3,731,648	$4,782,394
38	Book Depreciation	Line 18					$1,422,033	$2,133,050	$2,844,067
39	**Annual Revenue Requirement**	**Line 37 + Line 38**					**$3,936,772**	**$5,864,698**	**$7,626,461**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))

2/ Columns (a) through (c) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3. Column (d) is prorated for the 9-month FY December 2023 plan.

3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.

4/ Column (d) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 30, Column (a) through (c) and the end of the fiscal year on Line 30, Column (d). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2023-NG Incremental Capital Investments

Line No.				Apr 1-May 24, 2022 2023-NG (a)	PPL May 25-Dec 31, 2022 FY 2023 (b)	PPL Jan 1-Mar 31, 2023 FY 2023 (c)	(d)		(e)	(f)	(g)	(h)	(i)	(j)
	Capital Repairs Deduction													
1	Plant Additions	Page 25 of 46, Line 3, Columns (a) through (c)		$15,573,304	$63,735,189	$25,955,507	20 Year MACRS Depreciation							
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%	23.49%	23.49%								
3	Capital Repairs Deduction	Line 1 * Line 2		$3,657,390	$14,968,209	$6,095,651	MACRS basis:	Line 20, Column (a)					$11,915,914	
4													Annual	Cumulative
5	Bonus Depreciation						Fiscal Year						MACRS	Tax Depr
6	Plant Additions	Line 1		$15,573,304	$63,735,189	$25,955,507	FY Mar-2023 (Apr-May 2022)		3.750%				$446,847	$6,534,245
7	Plant Additions			$0	$0	$0								
8	Less Capital Repairs Deduction	Line 3		$3,657,390	$14,968,209	$6,095,651	PPL Acquisition - May 25, 2022							
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$11,915,914	$48,766,980	$19,859,856	Book Cost	Line 1, Column (a)					$15,573,304	
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	0.00%	0.00%	Cumulative Book Depreciation	- Page 25 of 46, Line 18, Col (a)					($210,383)	
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	$0	$0	MACRS basis from Acquisition:	Line 9(i) + Line 10(i)					$15,362,921	
12	Bonus Depreciation Rate	at 0%		0.00%	0.00%	0.00%	MACRS basis (Jun-Dec 2022)	Line 20, Column (b)					$48,766,980	
13	Total Bonus Depreciation Rate	Line 12		0.00%	0.00%	0.00%	Total MACRS Basis in 2022	Line 11(i) + Line 12(i)					$64,129,901	
14	Bonus Depreciation	Line 11 * Line 13		$0	$0	$0	MACRS basis (Jan-Mar 2023)	Line 20, Column (c)					$19,859,856	
15							Total MACRS Basis						$83,989,757	
16	Remaining Tax Depreciation													
17	Plant Additions	Line 1		$15,573,304	$63,735,189	$25,955,507			2022 Additions	2023 Additions	2022 Proration	2023 Proration		
18	Less Capital Repairs Deduction	Line 3		$3,657,390	$14,968,209	$6,095,651	FY Mar-2023 (Jun-Dec 2022)		3.750%				$2,404,871	$27,318,112
19	Less Bonus Depreciation	Line 14		$0	$0	$0	FY Mar-2023 (Jan-Mar 2023)		7.219%	3.750%	1.780%	0.925%	$1,325,165	$38,788,941
	Remaining Plant Additions Subject to 20 YR MACRS													
20	Tax Depreciation	Line 17 - Line 18 - Line 19		$11,915,914	$48,766,980	$19,859,856	CY 2023 (Apr-Dec 2023)		7.219%	3.750%	5.439%	2.825%	$4,049,117	$42,838,058
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	3.750%	3.750%	CY 2024		6.677%	7.219%			$5,715,636	$48,553,694
22	Remaining Tax Depreciation	Line 20 * Line 21		$446,847	$1,828,762	$744,745	CY 2025		6.177%	6.677%			$5,287,347	$53,841,041
23							CY 2026		5.713%	6.177%			$4,890,485	$58,731,525
24	FY23 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$18,501	$75,716	$30,835	CY 2027		5.285%	5.713%			$4,523,859	$63,255,384
25	Cost of Removal	Page 25 of 46, Line 10		$2,411,507	$9,869,315	$4,019,178	CY 2028		4.888%	5.285%			$4,184,263	$67,439,647
26							CY 2029		4.522%	4.888%			$3,870,704	$71,310,351
27	Total Tax Depreciation and Repairs Deductior	Sum of Lines 3, 14, 22, 24, and 25		$6,534,245	$26,742,002	$10,890,409	CY 2030		4.462%	4.522%			$3,759,539	$75,069,890
28							CY 2031		4.461%	4.462%			$3,746,982	$78,816,871
29	Reconcilation of MACRS Tax Depreciation:						CY 2032		4.462%	4.461%			$3,747,424	$82,564,296
30	Apr 1 -May 24, 2022 Plant Additions	Line 1, Column (a)			$15,573,304		CY 2033		4.461%	4.462%			$3,746,982	$86,311,277
31	Cumulative Book Depreciaiton through May 24, 2022	Page 25 of 46, Line 18, Col (a)			($210,383)		CY 2034		4.462%	4.461%			$3,747,424	$90,058,702
32	2022 Plant Additions (Net Book) through Acquisition	Line 30 + Line 31			$15,362,921		CY 2035		4.461%	4.462%			$3,746,982	$93,805,683
33	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%	7.219%	CY 2036		4.462%	4.461%			$3,747,424	$97,553,108
34	Remaining Tax Depreciation	Line 32 * Line 33	3/		$576,109	$1,109,049	CY 2037		4.461%	4.462%			$3,746,982	$101,300,089
35	2023 Proration Applied to Tax Year 2022 Additions	90 Days / 365 Days				24.658%	CY 2038		4.462%	4.461%			$3,747,424	$105,047,514
36	Jan-Mar 2023 Tax Depreciation on 2022 Additions	Line 34 * Line 35	4/			$273,464	CY 2039		4.461%	4.462%			$3,746,982	$108,794,495
37							CY 2040		4.462%	4.461%			$3,747,424	$112,541,920
38	MACRS Basis in Apr-Dec 2022 Plant Additions	Line 20, Column (b)			$48,766,980		CY 2041		4.461%	4.462%			$3,746,982	$116,288,901
39	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%	7.219%	CY 2042		2.231%	4.461%			$2,316,686	$118,605,588
40	Tax Depreciation on 2022 Additions	Line 38 * Line 39	3/		$1,828,761	$3,520,488	CY 2043			2.231%			$443,073	$119,048,661
41	2023 Proration Applied to Tax Year 2022 Additions	90 Days / 365 Days				24.658%			100.00%	100.00%			$83,989,757	
42	Jan-Mar 2023 Tax Depreciation on 2022 Additions	Line 40 * Line 41	4/			$868,066								
43														
44	MACRS Basis in Jan-Mar 2023 Plant Additions	Line 20, Column (c)				$19,859,856								
45	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946				3.750%								
46	Tax Depreciation on 2023 Additions	Line 44 * Line 45				$744,744								
47	Proration Applied to Tax Year 2023 Additions	90 Days / 365 Days				24.658%								
48	Jan-Mar 2023 Tax Depreciation on 2023 Additions	Line 46 * Line 47	4/			$183,635								
49														
50	Total MACRS Tax Depreciation	Sum of Lines 34, 40, Column (b) Sum of Lines 36, 42, 48, Column (c)			$2,404,869	$1,325,165								

1/ Per Tax Department
2/ Per Tax Department
3/ 2022 tax deprecation generated on the May 25 - Dec 31 2022 plant additions do not cross over rate year plans and, as such, do not need to be prorated as is done in prior years.
4/ 2023 tax deprecation generated on the May 25, 2022 - Mar 31, 2023 plant additions are prorated between the 3 months in the 2023 fiscal year plan and the 2023 9-month plan.

Column (g), Line 19 = MACRS Rate 7.219% / 365 days x 90 days
Column (g), Line 20 = MACRS Rate 7.219% / 365 days x 275 days
Column (h), Line 19 = MACRS Rate 3.750% / 365 days x 90 days
Column (h), Line 20 = MACRS Rate 3.750% / 365 days x 275 days

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2023-NG Incremental Capital Investment Pre CY 2024

Line No.	**Deferred Tax Subject to Proration**		4/1/22 - 5/24/2022 FY Mar-2023 (a)	5/25/22 - 12/31/22 FY Mar-2023 (b)	1/1/23 - 3/31/23 FY Mar-2023 (c)	9 Months Dec-2023 (d)
1	Book Depreciation	Page 25 of 46, Line 18, Columns (a) through (e)	$210,383	$861,012	$350,638	$2,133,050
2	Bonus Depreciation	- Page 26 of 46, Line 14	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 26 of 46, column (i), Lines 6,18,19,20	($446,847)	($2,404,871)	($1,325,165)	($4,049,117)
4	FY 2023 tax (gain)/loss on retirements	- Page 26 of 46, Line 24	($18,501)	($75,716)	($30,835)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($254,965)	($1,619,576)	($1,005,362)	($1,916,067)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($53,543)	($340,111)	($211,126)	($402,374)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 26 of 46, Line 3	($3,657,390)	($14,968,209)	($6,095,651)	
9	Cost of Removal	- Page 26 of 46, Line 25	($2,411,507)	($9,869,315)	($4,019,178)	
10	Book/Tax Depreciation Timing Difference at 3/31/2023					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($6,068,897)	($24,837,524)	($10,114,829)	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($1,274,468)	($5,215,880)	($2,124,114)	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($1,328,011)	($5,555,991)	($2,335,240)	($402,374)
15	Net Operating Loss	- Page 25 of 46, Line 26	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($1,328,011)	($5,555,991)	($2,335,240)	($402,374)
	Allocation of FY 2023 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($254,965)	($1,619,576)	($1,005,362)	($1,916,067)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($6,068,897)	($24,837,524)	($10,114,829)	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($6,323,861)	($26,457,100)	($11,120,191)	($1,916,067)
20	Total FY 2023 Federal NOL (Utilization)	- Page 25 of 46, Line 26 / 21%	$0	$0	$0	$0
21	Allocated FY 2023 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0	$0
22	Allocated FY 2023 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0	$0
23	Effective Tax Rate		21%	21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($53,543)	($340,111)	($211,126)	($402,374)

Line No.	**Proration Calculation**	(e) Number of Days in Month	(f) Proration Percentage	(g) FY Mar-2023	(h) FY Mar-2023	(i) FY Mar-2023	(j) Dec-2023
26	April	30	91.78%	($4,095)	($26,013)	($16,148)	($39,831)
27	May	31	83.29%	($3,716)	($23,606)	($14,653)	($34,791)
28	June	30	75.07%	($3,349)	($21,276)	($13,207)	($29,914)
29	July	31	66.58%	($2,971)	($18,869)	($11,713)	($24,874)
30	August	31	58.08%	($2,592)	($16,462)	($10,219)	($19,834)
31	September	30	49.86%	($2,225)	($14,132)	($8,773)	($14,957)
32	October	31	41.37%	($1,846)	($11,725)	($7,279)	($9,917)
33	November	30	33.15%	($1,479)	($9,396)	($5,832)	($5,040)
34	December	31	24.66%	($1,100)	($6,989)	($4,338)	
35	January	31	16.16%	($721)	($4,581)	($2,844)	
36	February	28	8.49%	($379)	($2,407)	($1,494)	
37	March	31	0.00%	$0	$0	$0	
38	Total	365		($24,473)	($155,457)	($96,501)	($179,158)
39	Deferred Tax Without Proration	Line 25		($53,543)	($340,111)	($211,126)	($402,374)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($26,771)	($170,055)	($105,563)	($201,187)
41	Proration Adjustment	Line 38 - Line 40		$2,298	$14,598	$9,062	$22,029

Column Notes:

(f)	Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (i)	Current Year Line 25 ÷ 12 × Current Month Col (f)
(j)	Current Year Line 25 ÷ 9 × Sum of remaining days in the Apr 1-Dec 31 period (Col (e)) ÷ 275

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2023-NG Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration		CY24 (a)
1	Book Depreciation	Page 25 of 46, Line 18, Column (f)	$2,844,067
2	Bonus Depreciation	- Page 26 of 46, Line 14	$0
3	Remaining MACRS Tax Depreciation	- Page 26 of 46, Column (i), Line 21	($5,715,636)
4	FY 2023 tax (gain)/loss on retirements	- Page 26 of 46, Line 24	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,871,570)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($603,030)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 26 of 46, Line 3	$0
9	Cost of Removal	- Page 26 of 46, Line 25	$0
10	Book/Tax Depreciation Timing Difference at 3/31/2023		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($603,030)
15	Net Operating Loss	- Page 25 of 46, Line 26	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($603,030)
	Allocation of FY 2023 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($2,871,570)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($2,871,570)
20	Total FY 2023 Federal NOL (Utilization)	- Page 25 of 46, Line / 21%	$0
21	Allocated FY 2023 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2023 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($603,030)

		(b)	(c)	(d)
	Proration Calculation	Number of Days in Month	Proration Percentage	CY24
26	January	31	91.53%	($45,996)
27	February	29	83.61%	($42,014)
28	March	31	75.14%	($37,758)
29	April	30	66.94%	($33,639)
30	May	31	58.47%	($29,383)
31	June	30	50.27%	($25,264)
32	July	31	41.80%	($21,007)
33	August	31	33.33%	($16,751)
34	September	30	25.14%	($12,632)
35	October	31	16.67%	($8,375)
36	November	30	8.47%	($4,256)
37	December	31	0.00%	$0
38	Total	366		($277,075)
39	Deferred Tax Without Proration	Line 25		($603,030)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($301,515)
41	Proration Adjustment	Line 38 - Line 40		$24,440

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 25 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on CY 2023 (9-Months) Forecasted Incremental Capital Investment

Line No.				9 months CY23 (a)	12 months CY24 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*	Page 45 of 46, Line 1		$39,031,000	
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Page 45 of 46, Line 13		$44,429,000	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$83,460,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$83,460,000	$0
5	Retirements	Company's Record		$19,606,050	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$63,853,950	$63,853,950
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$83,460,000	$0
8	Depreciation Expense	Page 40 of 46, Line 62, Col (d)		$49,906,920	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$33,553,080	$33,553,080
10	Cost of Removal	Company's Record		$14,007,000	$14,007,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$47,560,080**	**$47,560,080**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%	3.16%
13	Proration Percentage		2/	75.00%	
14	Vintage Year Tax Depreciation:				
15	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 30 of 46, Line 27, Column (a), Then = Line Page 30 of 46 , Column (d)		$23,972,854	$5,512,252
16	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$23,972,854	$29,485,106
17	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$756,669	$2,017,785
18	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$756,669	$2,774,454
19	Cumulative Book / Tax Timer	Line 16 - Line 18		$23,216,185	$26,710,652
20	Effective Tax Rate			21.00%	21.00%
21	Deferred Tax Reserve	Line 19 * Line 20		$4,875,399	$5,609,237
22	Add: CY 2023 Federal (NOL) Utilization	Company's Record		$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 21 through 22		$4,875,399	$5,609,237
	Rate Base Calculation:				
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$47,560,080	$47,560,080
25	Accumulated Depreciation	-Line 18		($756,669)	($2,774,454)
26	Deferred Tax Reserve	-Line 23		($4,875,399)	($5,609,237)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$41,928,011	$39,176,389
	Revenue Requirement Calculation:				
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 27 * 50%; Then = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$20,964,006	$40,552,200
29	Proration Adjustment	Page 31 of 46 & Page 32 of 46		$24,221	$29,741
30	Average ISR Rate Base after Deferred Tax Proration	Line 29 + Line 30		$20,988,227	$40,581,941
31	Pre-Tax ROR	Page 44 of 46, Line 33		8.23%	8.23%
32		Line 13		75.00%	
33	Return and Taxes	Year 1 = Lines 30 * 31 * 32; Then = Lines 30 * 31		$1,295,498	$3,339,894
34	Book Depreciation	Line 17		$756,669	$2,017,785
35	**Annual Revenue Requirement**	**Line 33 + Line 34**		**$2,052,168**	**$5,357,679**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))
2/ Fiscal Year December 2023 is prorated for 9 months.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on CY 2023 (9-Months) Incremental Capital Investments

Line No.				9 Months Calendar Year Dec-2023 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 29 of 46, Line 3		$83,460,000	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%				
3	Capital Repairs Deduction	Line 1 * Line 2		$7,102,446	MACRS basis:	Line 20	$76,357,554	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$83,460,000	Dec-2023	3.750%	$2,863,408	$23,972,854
7	Plant Additions			$0	Dec-2024	7.219%	$5,512,252	$29,485,106
8	Less Capital Repairs Deduction	Line 3		$7,102,446	Dec-2025	6.677%	$5,098,394	$34,583,500
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$76,357,554	Dec-2026	6.177%	$4,716,606	$39,300,106
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Dec-2027	5.713%	$4,362,307	$43,662,413
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Dec-2028	5.285%	$4,035,497	$47,697,910
12	Bonus Depreciation Rate	at 0%		0.00%	Dec-2029	4.888%	$3,732,357	$51,430,267
13	Total Bonus Depreciation Rate	Line 12		0.00%	Dec-2030	4.522%	$3,452,889	$54,883,155
14	Bonus Depreciation	Line 11 * Line 13		$0	Dec-2031	4.462%	$3,407,074	$58,290,229
15					Dec-2032	4.461%	$3,406,310	$61,696,540
16	Remaining Tax Depreciation				Dec-2033	4.462%	$3,407,074	$65,103,614
17	Plant Additions	Line 1		$83,460,000	Dec-2034	4.461%	$3,406,310	$68,509,925
18	Less Capital Repairs Deduction	Line 3		$7,102,446	Dec-2035	4.462%	$3,407,074	$71,916,999
19	Less Bonus Depreciation	Line 14		$0	Dec-2036	4.461%	$3,406,310	$75,323,309
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$76,357,554	Dec-2037	4.462%	$3,407,074	$78,730,383
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Dec-2038	4.461%	$3,406,310	$82,136,694
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,863,408	Dec-2039	4.462%	$3,407,074	$85,543,768
23					Dec-2040	4.461%	$3,406,310	$88,950,078
24	CY23 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0	Dec-2041	4.462%	$3,407,074	$92,357,152
25	Cost of Removal	Page 29 of 46, Line 10		$14,007,000	Dec-2042	4.461%	$3,406,310	$95,763,463
26					Dec-2043	2.231%	$1,703,537	$97,467,000
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$23,972,854		100.00%	$76,357,554	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2023 (9-Months) Incremental Capital Investment Pre CY 2024

Line No.	Deferred Tax Subject to Proration		9 months CY23 (a)
1	Book Depreciation	Page 29 of 46, Line 17	$756,669
2	Bonus Depreciation	- Page 30 of 46, Line 14	$0
3	Remaining MACRS Tax Depreciation	- Page 30 of 46, column (d), Line 6	($2,863,408)
4	CY 2023 tax (gain)/loss on retirements	- Page 30 of 46, Line 24	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,106,739)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($442,415)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 30 of 46, Line 3	($7,102,446)
9	Cost of Removal	- Page 30 of 46, Line 25	($14,007,000)
10	Book/Tax Depreciation Timing Difference at 3/31/2023		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($21,109,446)
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($4,432,984)
14	Total Deferred Tax Reserve	Line 7 + Line 13	($4,875,399)
15	Net Operating Loss	Page 29 of 46, Line 22	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($4,875,399)
	Allocation of CY 2023 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($2,106,739)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($21,109,446)
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($23,216,185)
20	Total CY 2023 Federal NOL (Utilization)	- Page 29 of 46, Line 22 / 21%	$0
21	Allocated CY 2023 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated CY 2023 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($442,415)

	Proration Calculation	(b) Number of Days in Month	(c) Proration Percentage	(d) CY23
26	April	30	89.09%	($43,795)
27	May	31	77.82%	($38,253)
28	June	30	66.91%	($32,891)
29	July	31	55.64%	($27,349)
30	August	31	44.36%	($21,808)
31	September	30	33.45%	($16,445)
32	October	31	22.18%	($10,904)
33	November	30	11.27%	($5,541)
34	December	31	0.00%	$0
35			0.00%	$0
36			0.00%	$0
37			0.00%	$0
38	Total	275		($196,986)
39	Deferred Tax Without Proration	Line 25		($442,415)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($221,208)
41	Proration Adjustment	Line 38 - Line 40		$24,221

Column Notes:
(c) Sum of remaining days in the Apr 1-Dec 31 period (Col (b)) ÷ 275
(d) Current Year Line 25 ÷ 9 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2023 (9-Months) Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration		12 months (a) CY24
1	Book Depreciation	Page 29 of 46, Line 17	$2,017,785
2	Bonus Depreciation	- Page 30 of 46, Line 14	$0
3	Remaining MACRS Tax Depreciation	- Page 30 of 46, column (d), Line 7	($5,512,252)
4	CY 2023 tax (gain)/loss on retirements	- Page 30 of 46, Line 24	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,494,467)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($733,838)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 30 of 46, Line 3	$0
9	Cost of Removal	- Page 30 of 46, Line 25	$0
10	Book/Tax Depreciation Timing Difference at 3/31/2023		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($733,838)
15	Net Operating Loss	Page 29 of 46, Line 22	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($733,838)
	Allocation of FY 2024 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,494,467)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($3,494,467)
20	Total FY 2024 Federal NOL (Utilization)	- Page 29 of 46, Line 22 / 21%	$0
21	Allocated FY 2024 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2024 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($733,838)

Line No.	Proration Calculation	(b) Number of Days in Month	(c) Proration Percentage	(d) CY24
26	January	31	91.53%	($55,974)
27	February	29	83.61%	($51,128)
28	March	31	75.14%	($45,948)
29	April	30	66.94%	($40,936)
30	May	31	58.47%	($35,756)
31	June	30	50.27%	($30,744)
32	July	31	41.80%	($25,564)
33	August	31	33.33%	($20,384)
34	September	30	25.14%	($15,372)
35	October	31	16.67%	($10,192)
36	November	30	8.47%	($5,180)
37	December	31	0.00%	$0
38	Total	366		($337,178)
39	Deferred Tax Without Proration	Line 25		($733,838)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($366,919)
41	Proration Adjustment	Line 38 - Line 40		$29,741

Column Notes:
(c) Sum of remaining days in the year (Col (b)) ÷ 366
(d) Current Year Line 25 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
21-Month Revenue Requirement on CY 2024 (12-Months) Forecasted Incremental Capital Investment

Line No.				PPL Fiscal Year Dec-2024 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	Page 46 of 46, Line 1		$96,737,000
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Page 46 of 46, Line 13		$55,125,000
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$151,862,000
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$151,862,000
5	Retirements	Company's Record		$35,674,742
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$116,187,258
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$151,862,000
8	Depreciation Expense	Page 40 of 46, Line 62, Col (d)		$49,906,920
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$101,955,080
10	Cost of Removal	Company's Record		$13,529,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$115,484,080**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	Page 38 of 46, Line 3, Col (e)	1/	3.16%
13	Vintage Year Tax Depreciation:			
14	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 34 of 46, Line 27, Column (a), Then = Line Page 34 of 46 , Column (d)		$31,662,651
15	Cumulative Tax Depreciation-PPL	Prior Year Line 15 + Current Year Line 14		$31,662,651
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,835,759
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,835,759
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$29,826,892
19	Effective Tax Rate			21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$6,263,647
21	Add: FY 2024 Federal (NOL) Utilization	Company's Record		$0
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$6,263,647
	Rate Base Calculation:			
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$115,484,080
24	Accumulated Depreciation	-Line 17		($1,835,759)
25	Deferred Tax Reserve	-Line 22		($6,263,647)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$107,384,673
	Revenue Requirement Calculation:			
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 26 * 50%; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2		$53,692,337
28	Proration Adjustment	Page 27 of 46, Line 41		$28,720
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$53,721,056
30	Pre-Tax ROR	Page 44 of 46, Line 33		8.23%
31	Return and Taxes	Line 29 * Line 30		$4,421,243
32	Book Depreciation	Line 16		$1,835,759
33	**Annual Revenue Requirement**	**Line 31 + Line 32**		**$6,257,002**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 38 of 46, Line 3, Col (e))

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on CY 2024 (12-Months) Incremental Capital Investments

Line No.				12 Months Calendar Year Dec-2024 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 33 of 46, Line 3		$151,862,000	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%				
3	Capital Repairs Deduction	Line 1 * Line 2		$12,923,456	MACRS basis:	Line 20	$138,938,544	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$151,862,000	Dec-2024	3.750%	$5,210,195	$31,662,651
7	Plant Additions			$0	Dec-2025	7.219%	$10,029,973	$41,692,624
8	Less Capital Repairs Deduction	Line 3		$12,923,456	Dec-2026	6.677%	$9,276,927	$50,969,551
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$138,938,544	Dec-2027	6.177%	$8,582,234	$59,551,785
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Dec-2028	5.713%	$7,937,559	$67,489,344
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Dec-2029	5.285%	$7,342,902	$74,832,246
12	Bonus Depreciation Rate	at 0%		0.00%	Dec-2030	4.888%	$6,791,316	$81,623,562
13	Total Bonus Depreciation Rate	Line 12		0.00%	Dec-2031	4.522%	$6,282,801	$87,906,363
14	Bonus Depreciation	Line 11 * Line 13		$0	Dec-2032	4.462%	$6,199,438	$94,105,801
15					Dec-2033	4.461%	$6,198,048	$100,303,849
16	Remaining Tax Depreciation				Dec-2034	4.462%	$6,199,438	$106,503,287
17	Plant Additions	Line 1		$151,862,000	Dec-2035	4.461%	$6,198,048	$112,701,336
18	Less Capital Repairs Deduction	Line 3		$12,923,456	Dec-2036	4.462%	$6,199,438	$118,900,773
19	Less Bonus Depreciation	Line 14		$0	Dec-2037	4.461%	$6,198,048	$125,098,822
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$138,938,544	Dec-2038	4.462%	$6,199,438	$131,298,260
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Dec-2039	4.461%	$6,198,048	$137,496,308
22	Remaining Tax Depreciation	Line 20 * Line 21		$5,210,195	Dec-2040	4.462%	$6,199,438	$143,695,746
23					Dec-2041	4.461%	$6,198,048	$149,893,794
24	CY24 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0	Dec-2042	4.462%	$6,199,438	$156,093,232
25	Cost of Removal	Page 33 of 46, Line 10		$13,529,000	Dec-2043	4.461%	$6,198,048	$162,291,281
26					Dec-2044	2.231%	$3,099,719	$165,391,000
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$31,662,651		100.00%	$138,938,544	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Net Deferred Tax Reserve Proration on CY 2024 (12-Months) Incremental Capital Investment Post CY 2023

Line No.	Deferred Tax Subject to Proration		(a) CY24
1	Book Depreciation	Page 33 of 46, Line 16	$1,835,759
2	Bonus Depreciation	Page 34 of 46, Line 14	$0
3	Remaining MACRS Tax Depreciation	- Page 34 of 46, column (d)	($5,210,195)
4	FY 2024 tax (gain)/loss on retirements	- Page 34 of 46, Line 24	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,374,437)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($708,632)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 34 of 46, Line 3	($12,923,456)
9	Cost of Removal	- Page 34 of 46, Line 25	($13,529,000)
10	Book/Tax Depreciation Timing Difference at 3/31/2024		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($26,452,456)
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($5,555,016)
14	Total Deferred Tax Reserve	Line 7 + Line 13	($6,263,647)
15	Net Operating Loss	- Page 33 of 46, Line 21	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($6,263,647)
	Allocation of FY 2024 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,374,437)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($26,452,456)
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($29,826,893)
20	Total FY 2024 Federal NOL (Utilization)	- Page 33 of 46, Line 22 / 21%	$0
21	Allocated FY 2024 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2024 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($708,632)

Line No.	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) CY24
26	January	31	91.53%	($54,051)
27	February	29	83.61%	($49,372)
28	March	31	75.14%	($44,370)
29	April	30	66.94%	($39,530)
30	May	31	58.47%	($34,528)
31	June	30	50.27%	($29,688)
32	July	31	41.80%	($24,686)
33	August	31	33.33%	($19,684)
34	September	30	25.14%	($14,844)
35	October	31	16.67%	($9,842)
36	November	30	8.47%	($5,002)
37	December	31	0.00%	$0
38	Total	366		($325,596)
39	Deferred Tax Without Proration	Line 25		($708,632)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($354,316)
41	Proration Adjustment	Line 38 - Line 40		$28,720

Column Notes:

(d) Sum of remaining days in the year (Col (c)) ÷ 365

(e) & (f) Current Year Line 25 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2018 - 2023 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)	Fiscal Year 2023 (f)
	Capital Investment							
1	ISR - Eligible Capital Investment	Col (a) = FY 2018 ISR Docket No.4682, Att MAL-1 P2, L3; Col (b)=FY 2019 ISR Docket No.4783, Att PCE-1 P3, Table 1; Col (c)= Section I of Att. PCE-1, Table 2	$92,659,654	$111,243,061	$103,267,720	$116,486,800	$88,762,702	$105,264,000
2	Intangible Assest included in Total Allowed Discretionary Capital	Col (a) =0; Col (b) = FY 2019 ISR Docket No. 4783, Att. MAL-1,Page 30 of 38, Line13; Col (c) = Actual per Operation	$0	$3,460,626	$0	$0	$0	$0
3	ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k)	$74,843,000	$74,843,000	$31,184,583	$0	$0	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$17,816,654	$32,939,435	$72,083,137	$116,486,800	$88,762,702	$105,264,000
	Cost of Removal							
5	ISR - Eligible Cost of Removal	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)= Section 1 of Att. PCE-1, Table 3	$9,979,698	$7,949,082	$14,387,482	$11,299,204	$7,744,459	$16,300,000
6	ISR - Eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L10×3÷12, [P1]L26+L45×7÷12; Col(b)=[P1]L45×5÷12+[P2]L18×7÷12; Col (c) = [P2]L18×5÷12+L39×7÷12	$8,259,707	$7,848,009	$3,437,925	$205,400	$85,583	$0
7	Incremental Cost of Removal	Line 5 - Line 6	$1,719,991	$101,073	$10,949,557	$11,093,804	$7,658,876	$16,300,000
	Retirements							
8	ISR - Eligible Retirements/Actual	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)=Per Company's Book	$15,206,748	$12,015,754	$13,944,441	$22,589,226	$35,100,171	$15,261,889
9	ISR - Eligible Retirements in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L5×3÷12+[P1]L25+L27+L46×7÷12; Col(b)=[P1]L46×5÷12+[P2]L19×7÷12; Col (c)=[P2]L19×5÷12+L40×7÷12	$20,451,820	$22,665,233	$9,928,809	$593,200	$247,167	$0
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$4,015,632	$21,996,026	$34,853,004	$15,261,889
	Net NOL Position							
11	ISR - (NOL)/Utilization	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2021 ISR Plan Docket No. 4995, Col (c)=Per Tax Departmen	($4,571,409)	$1,506,783	$0	$1,695,589	$8,772,838	$0
12	less: (NOL)/Utilization recovered in transmission rates	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11	($1,572,911)	$515,161	$0	$570,357	$2,983,755	$0
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 37 of 46, Line 12	($2,998,499)	$991,622	$0	$1,125,232	$5,789,083	$43,783
14	(NOL)/Utilization in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P. 12: Col (c)= L39×7÷12	$0	$0	$1,462,980	$6,764,379	$4,085,281	$0
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$991,622	($1,462,980)	($5,639,147)	$1,703,802	$43,783

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b) Test Year July 2016 - June 2017	(c)	(d)	(e)		(d) Jul & Aug 2017	(e) 12 Mths Aug 31 2018	(f) 12 Mths Aug 31 2019	(g) 12 Mths Aug 31 2020	(h) 12 Mths Aug 31 2021	(i) 13 Mths Aug 31 2022
1	Total Base Rate Plant DIT Provision		$18,265,666					$2,580,654	$5,847,765	$4,355,117	$707,056	$3,826,291	$0
2	Excess DIT Amortization									($3,074,665)	($3,074,665)	($3,074,665)	$0
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023-NG	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023-NG
3	Total Base Rate Plant DIT Provision							$10,558,267	$3,183,499	($847,583.55)	($548,055)	$313,177	$0
4	Incremental FY 18	$4,261,399	$4,223,434	$4,181,310	$4,130,879	$4,072,741	$4,063,088	$4,261,399	($37,965)	($42,125)	($50,431)	($58,138)	($9,653)
5	Incremental FY 19	$0	$2,128,597	$2,305,665	$2,485,863	$2,504,666	$2,193,670		$2,128,597	$177,068	$180,198	$18,803	($310,996)
6	Incremental FY 20			$4,774,661	$5,289,496	$5,731,763	$5,787,291			$4,774,661	$514,834	$442,268	$55,527
7	Incremental FY 21				$9,206,417	$9,930,574	$10,022,701				$9,206,417	$724,158	$92,127
8	Incremental FY 22					$4,105,561	$4,234,773					$4,105,561	$129,212
9	Incremental FY 23												$0
10	TOTAL Plant DIT Provision	$4,261,399	$6,352,031	$11,261,635	$21,112,654	$26,345,306	$26,301,523	$14,819,666	$5,274,131	$4,062,021	$9,302,963	$5,545,830	($43,783)
11	Distribution-related NOL							$2,998,499	($991,622)	$0	($1,125,232)	($5,789,083)	-
12	Lesser of Distribution-related NOL or DIT Provision							$2,998,499	($991,622)	$0	($1,125,232)	($5,789,083)	($43,783)
13	Total NOL												-
14	NOL recovered in transmission rates												-
15	Distribution-related NOL												-

Line Notes:

1(b)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 2 of 23, Line 29, Col (e) - (a)
1(d)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 3
1(e)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 7
1(f)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 50
2	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Sch. 11-ELEC, P.11 of 20, L. 51; P. 12 of 20, L. 42 & 52
3	Col(e) = Line 1(b)÷12×3+ Line1(d) + Line1(e)÷12×7; Col (f) = (Line1(e) + Line2(e))÷12×5 + (Line1(f) + Line2(f))÷12×7; Col (g) = (Line1(f) + Line2(f))÷12×5 + (Line1(g) + Line2(g))÷12×7
4(a)~(d)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.20(a)+L.22(a); P.2, L.20(b)+L.22(b); P.2, L.20(c)+L.22(c); P.2, L.20(d)+L.22(d))
5(b)~(d)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.5, L.20(a)+P.8, L.23(c); P.5, L.20(b)+P.8, L.23(f); P.5, L.20(c)+P.8, L.23(i))
6(c)~(d)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.10, L.20(a): P.10, L.20(b))
7(d)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.13, L.20(a)+P.15, L.23(a))
4(e) -7(g)	Year over year change in cumulative DIT shown in Cols (a) through (d)
10	Sum of Lines 3 through 7
11	Page 36 of 46, Line 13
12	Lesser of Line 10 or Line 11
13	Per Tax Department
14	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 13
15	Line 13 - Line 14

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 3 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line	Account		Description	Adjusted Plant Balance (a)	Approved Rate (b)	Test Year Depreciation (c) = (a) x (b)
			Intangible Plant			
1	303.00		Intangible Cap Software	($0)	0.00%	$0
2						
3			Total Intangible Plant	($0)		$0
4						
5			Production Plant			
6						
7	330.00		Land Hydro	$6,989	0.00%	$0
8	331.00		Struct & Improvements	$1,993,757	0.00%	$0
9	332.00		Reservoirs Dams And Water	$1,125,689	0.00%	$0
10						
11			Total Production Plant	$3,126,434		$0
12						
13			Total Transmission Plant	$0		$0
14						
15			Distribution Plant			
16						
17	360		Land & Land Rights New	$ -	0.00%	$ -
18	362		Station Equipment	$ -	2.32%	$ -
19	365		Overhead Conductors and Devices	$ -	3.02%	$ -
20	367.1		Underground Conductors and Devices	$ -	2.52%	$ -
21	360.00		Land & Land Rights New	$ 12,874,490	0.00%	$ -
22	360.10		Land Structures & Dist	$ 95,396	0.00%	$ -
23	361.00		Struct & Improvements	$ 10,144,741	1.36%	$ 137,968
24	362.00		Station Equipment	$ 253,879,227	2.19%	$ 5,559,955
25	362.10		Station Equip Pollution	$ 71,597	2.19%	$ 1,568
26	362.55		Station Equipment - Energy Management Syst	$ 663,280	6.70%	$ 44,440
27	364.00		Poles, Towers And Fixtures	$ 237,914,852	4.27%	$ 10,158,964
28	365.00		Oh Conduct-Smart Grid	$ 308,051,305	2.65%	$ 8,163,360
29	366.10		Underground Manholes A	$ 23,368,987	1.33%	$ 310,808
30	366.20		Underground Conduit	$ 48,513,051	1.55%	$ 751,952
31	367.10		Underground Conductors	$ 173,808,945	3.42%	$ 5,944,266
32	368.10		Line Transformers - Stations	$ 10,674,398	2.76%	$ 294,613
33	368.20		Line Transformers - Bare Cost	$ 101,452,162	3.14%	$ 3,180,525
34	368.30		Line Transformers - Install Cost	$ 77,701,753	3.22%	$ 2,501,996
35	369.10		Overhead Services	$ 83,166,615	5.04%	$ 4,191,597
36	369.20		Underground Services C	$ 1,691,919	4.87%	$ 82,396
37	369.21		Underground Services C	$ 22,150,773	4.87%	$ 1,078,743
38	370.10		Meters - Bare Cost - Domestic	$ 26,366,117	5.61%	$ 1,479,139
39	370.20		Meters - Install Cost - Domestic	$ 10,026,102	5.81%	$ 582,517
40	370.30		Meters - Bare Cost - Large	$ 11,492,790	5.69%	$ 653,940
41	370.35		Meters - Install Cost - Large	$ 9,186,534	5.13%	$ 471,269
42	371.00		Installation On Custom	$ 119,825	3.61%	$ 4,326
43	373.10		Oh Steetlighting	$ 23,671,126	1.46%	$ 345,598
44	373.20		Ug Streetlighting	$ 16,012,987	1.52%	$ 243,397
45	374.00	1/	Elect Equip ARO	$ -	0.00%	$ -
46						
47			Total Distribution Plant	$ 1,463,098,971	**3.16%**	$ 46,183,339
48						
49			General Plant			
50						
51	389.00		Land And Land Rights	$ 842,411	0.00%	$ -
52	390.00		Struct And Improvement Electric	$ 34,216,272	2.28%	$ 780,131
53	391.00		Office Furn &Fixt Electric (Fully Dep)	$ 30,645	0.00%	$ 29,542
54	391.00		Office Furn &Fixt Electric	$ 412,269	6.67%	$ 27,498
55	393.00		Stores Equipment	$ 93,412	5.00%	$ 4,671
56	394.00		General Plant Tools Shop	$ 1,934,730	5.00%	$ 96,736
57	395.00		General Plant Laboratory (Fully Dep)	$ 288,227	0.00%	$ -
58	395.00		General Plant Laboratory (Fully Dep)	$ 1,226,832	6.67%	$ 81,830
59	397.00		Communication Equipment	$ 5,337,629	5.00%	$ 266,881
60	397.10		Communication Equipment Site Specific	$ 2,530,920	3.90%	$ 98,706
61	397.50		Communication Equipment Network	$ 49,498	5.00%	$ 2,475
62	398.00		General Plant Miscellaneous	$ 706,169	6.67%	$ 47,101
63	399.00		Other Tangible Property	$ 12,484	0.00%	$ -
64	399.10	1/	ARO	$ (0)	0.00%	$ -
65						
66			Total General Plant	$ 47,681,498	**3.01%**	$ 1,435,572
67						
68			Grand Total - All Categories	$ 1,513,906,902	**3.15%**	$ 47,618,911

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Rate per RIPUC Docket No. 4995

Line	Description	Adjusted Plant Balance (d)	Average Rate (e)=(f)/(d)	Approved Depreciation (f)
1	Total Distribution Plant	$ 1,463,098,971	3.16%	$ 46,183,339
2	Communication Equipment	$ 7,918,047	4.65%	$ 368,062
3	Total ISR eligible Plant	$ 1,471,017,018	**3.16%**	$ 46,551,401
4				
5	Non-ISR or Communication Plant	$ 42,889,885		
6	Grand Total - All Plant	$ 1,513,906,902		

Line Notes:
1 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on left Line 47
2 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
3 Line 1+Line 2
5 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
6 Line 3+Line 6

Column Notes:

(a) - (c) - Per Docket 4770/4780 Compliance Attachment 2, Schedule 6 ELEC, Pages 3 & 4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 1 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense in Base Rates

Line No.	Description		Reference	Amount		less non-ISR eligible plant	ISR Eligible Amount
			(a)	(b)		(c)	(d)
1	Total Company Rate Year Distribution Depreciation Expense		Sum of Page 2, Line 16 and Line 17	$50,128,332	1		
2	Test Year Depreciation Expense		Per Company Books	$69,031,187	2		
3	Less : Test Year IFA related Depreciation Expense		Page 4, Line 30, Column (c)	($19,814,202)	3		
4	Less: ARO and other adjustments		Page 4, Line 30, Column (b) + Column (d)	($55,610)	4		
5	Adjusted Total Company Test Year Distribution Depreciation Expense		Sum of Line 2 through Line 4	$49,161,375	5		
6	Depreciation Expense Adjustmen		Line 1 - Line 5	$966,957	6		
7					7		
8				Per Book	8		
9	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount	9		
10	Total Distribution Utility Plant 06/30/17		Page 4, Line 28, Column (e)	$2,141,474,644	10	($39,763,450)	$2,101,711,193
11	Less Non Depreciable Plant		Page 4, Line 26, Column (e)	($627,567,742)	11		($627,567,742)
12	Depreciable Utility Plant 6/30/17		Line 10 + Line 11	$1,513,906,902	12	($39,763,450)	$1,474,143,451
13					13		
14	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-ELEC, Page 6, Line 7	$12,473,833	14	$0	$12,473,833
15	Less: Streetlights retired in the 2 Mos Ended 08/31/17		Per Company Books	($1,057,011)	15	$0	($1,057,011)
16	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 14 x Retirement Rate	($3,699,739)	16	$0	($3,699,739)
17	Depreciable Utility Plant 08/31/17		Line 12 + Line 14 + Line 16	$1,521,623,985	17	($39,763,450)	$1,481,860,535
18					18		
19	Average Depreciable Plant from 06/30/17 to 08/31/17		(Line 12 + Line 17)/2	$1,517,765,443	19		$1,478,001,993
20					20		
21	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	21		3.40%
22					22		
23	Book Depreciation Reserve 06/30/17		Page 5, Line 69, Column (e)	$652,405,159	23		
24	Plus: Book Depreciation Expense excluding Streetlight Retirement		1/6 of (Line 19 excl. Line 15 x Line 21)	$8,603,666	24		$8,381,334
25	Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2 Mos		1/12 of (Line 15 x SL Dep Rate)	($1,307)	25		($1,307)
26	Less: Net Cost of Removal/(Salvage)	2/	Line 14 x Cost of Removal Rate	($1,281,063)	26		
27	Less: Retired Plant		Line 16	($3,699,739)	27		
28	Book Depreciation Reserve 08/31/17		Sum of Line 23 through Line 27	$656,026,715	28		
29					29		
30	Depreciation Expense 12 Months Ended 08/31/18				30		
31	Total Utility Plant 08/31/17		Line 10 + Line 14 + Line 15 + Line 16	$2,149,191,727	31	($39,763,450)	$2,109,428,277
32	Less Non Depreciable Plant		Line 11	($627,567,742)	32	$0	($627,567,742)
33	Depreciable Utility Plant 08/31/17		Line 31 + Line 32	$1,521,623,985	33	($39,763,450)	$1,481,860,535
34					34		
35	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-ELEC, Page 6, Line 14	$74,843,000	35	$0	$74,843,000
36	Less: Plant Retired in 12 Months Ended 08/31/18	1/	Line 35 x Retirement rate	($22,198,434)	36	$0	($22,198,434)
37	Depreciable Utility Plant 08/31/18		Sum of Line 33 through Line 36	$1,574,268,551	37	($39,763,450)	$1,534,505,101
38					38		
39	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 33 + Line 37)/2	$1,547,946,268	39	($39,763,450)	$1,508,182,818
40					40		
41	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	41		3.40%
42					42		
43	Book Depreciation Reserve 08/31/17		Line 28	$656,026,715	43		
44	Plus: Book Depreciation 08/31/18		Line 39 x Line 41	$52,630,173	44		$51,278,216
45	Less: Net Cost of Removal/(Salvage)	2/	Line 35 x Cost of Removal Rate	($7,686,376)	45		
46	Less: Retired Plant		Line 36	($22,198,434)	46		
47	Book Depreciation Reserve 08/31/18		Sum of Line 43 through Line 46	$678,772,079	47		

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 29.66%
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY1 10.27%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment 1
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2019
1	Plant In Service	$1,595,499	$111,243	$3,137	$114,380		($12,016)		$1,697,863
2	Accumulated Depr	$672,116				$52,896	($12,016)	($7,949)	$705,047
3	Net Plant	$923,383							$992,816
4	Property Tax Expense	$30,354							$32,077
5	Effective Prop Tax Rate	3.29%							3.23%
	Effective tax Rate Calculation	End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2020
6	Plant In Service	$1,697,863	$103,268	$4,244	$107,511		($14,649)		$1,790,725
7	Accumulated Depr	$705,047				$54,318	($14,649)	($14,387)	$730,328
8	Net Plant	$992,816							$1,060,397
9	Property Tax Expense	$32,077							$32,568
10	Effective Prop Tax Rate	3.23%							3.07%
	Effective Tax Rate Calculation	End of FY 2020	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2021
11	Plant In Service	$1,790,725	$116,487	$2,024	$118,510		($22,589)		$1,886,646
12	Accumulated Depr	$730,328				$57,246	($22,589)	($11,374)	$753,611
13	Net Plant	$1,060,397							$1,133,035
14	Property Tax Expense	$32,568							$33,333
15	Effective Prop Tax Rate	3.07%							2.94%
	Effective Tax Rate Calculation	End of FY 2021	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2022
16	Plant In Service	$1,886,646	$88,763	$13,092	$101,855		($35,100)		$1,953,401
17	Accumulated Depr	$753,611				$59,937	($35,100)	($7,744)	$770,703
18	Net Plant	$1,133,035							$1,182,699
19	Property Tax Expense	$33,333							$33,955
20	Effective Prop Tax Rate	2.94%							2.87%
	Effective Tax Rate Calculation	End of FY 2022	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2023
21	Plant In Service	$1,953,401	$105,264	$2,024	$107,288		($15,262)		$2,045,427
22	Accumulated Depr	$770,703				$62,623	($15,262)	($16,300)	$801,764
23	Net Plant	$1,182,699							$1,243,663
24	Property Tax Expense	$33,955							$36,589
25	Effective Prop Tax Rate	2.87%							2.94%
	Effective Tax Rate Calculation	End of FY 2023	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of CY 2023
26	Plant In Service	$2,045,427	$83,460	$9,819	$93,279		($19,606)		$2,119,100
27	Accumulated Depr	$801,764				$63,780	($19,606)	($14,007)	$831,931
28	Net Plant	$1,243,663							$1,287,170
29	Property Tax Expense	$36,589							$36,955
30	Effective Prop Tax Rate	2.94%							2.87%
	Effective Tax Rate Calculation	End of CY 2023	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2024
31	Plant In Service	$2,119,100	$151,862	$13,092	$164,954		($35,675)		$2,248,380
32	Accumulated Depr	$831,931				$65,813	($35,675)	($13,529)	$848,539
33	Net Plant	$1,287,170							$1,399,841
34	Property Tax Expense	$36,955							$40,189
35	Effective Prop Tax Rate	2.87%							2.87%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment 2 (continued)
(000s)

	Property Tax Recovery Calculation	(a)	(b)	(c)	(d	(e)	(f)	(g)	(h)	(i)
		Cumulative Increm. ISR Prop. Tax for FY2018			Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 months			Cumulative Increm. ISR Prop. Tax for FY2019 7 months		
36	Incremental ISR Additions		$92,660			$111,243			$36,400	
37	Book Depreciation: base allowance on ISR eligible plant		($43,032)			($43,032)			$0	
38	Book Depreciation: current year ISR additions		($1,317)			($1,628)			($999)	
39	COR		$9,980			$7,949			$101	
40	Net Plant Additions		$58,291			$74,532			$35,502	
41	RY Effective Tax Rate		3.98%			3.98%			3.28% 1.91%	
42	ISR Year Effective Tax Rate	3.29%			3.23%					
43	RY Effective Tax Rate	3.98%	-0.69%		3.98%	-0.75%		3.23%		
44	RY Effective Tax Rate 5 mos for FY 2019		-0.69%		5 month	-0.31%		3.28%	-0.05%	
45	RY Net Plant times 5 mo rate	$746,900	-0.69%	($5,191)	$746,900	-0.31%	($2,338)		-0.03% 7 mos	
46	FY 2014 Net Adds times ISR Year Effective Tax rate	$1,566	3.29%	$51	$1,232	1.35%	$17	$930,873	-0.03%	($279)
47	FY 2015 Net Adds times ISR Year Effective Tax rate	$34,308	3.29%	$1,128	$32,324	1.35%	$435			
48	FY 2016 Net Adds times ISR Year Effective Tax rate	$33,535	3.29%	$1,102	$32,090	1.35%	$432	$18,393	1.88%	$346
49	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	3.29%	$1,256	$37,040	1.35%	$499	$35,502	1.88%	$669
50	FY 2018 Net Adds times ISR Year Effective Tax rate	$58,291	3.29%	$1,916	$55,850	1.35%	$752			
51	FY 2019 Net Adds times ISR Year Effective Tax rate				$74,532	1.35%	$1,003			
52	Total ISR Property Tax Recovery			$263			$800			$736

		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		Cumulative Increm. ISR Prop. Tax for FY2020			Cumulative Increm. ISR Prop. Tax for FY2021			Cumulative Increm. ISR Prop. Tax for FY2022		
53	Incremental ISR Additions		$72,083			$116,487			$88,763	
54	Book Depreciation: base allowance on ISR eligible plant		$0			$0			($29,112)	
55	Book Depreciation: current year ISR additions		($1,075)			($1,493)			($852)	
56	COR		$10,950			$11,094			$7,659	
57	Net Plant Additions		$81,957			$126,088			$66,457	
58	RY Effective Tax Rate		3.38%			3.58%			3.66%	
59	ISR Property Tax Recovery on non-ISR									
60	ISR Year Effective Tax Rate	3.07%			2.94%			2.87%		
61	RY Effective Tax Rate	3.38%	-0.31%		3.58%	-0.63%		3.66%	-0.79%	
62	RY Effective Tax Rate 7 mos for FY 2019									
63	RY Net Plant times Rate Difference	$902,404	-0.31%	($2,816)	$853,576	* -0.63%	($5,418)	$833,223	* -0.79%	($6,607)
64	Non-ISR plant times rate difference	($2,269)	-0.31%	$7	($4,269)	* -0.63%	$27	($6,269)	* -0.79%	$50
65	FY 2018 Net Incremental times rate difference	$17,664	3.07%	$543	$16,935	* 2.94%	$498	$16,207	* 2.87%	$465
66	FY 2019 Net Incremental times rate difference	$33,630	3.07%	$1,033	$31,759	* 2.94%	$934	$29,887	* 2.87%	$858
67	FY 2020 Net Incremental times rate difference	$81,957	3.07%	$2,517	$79,806	* 2.94%	$2,348	$77,655	* 2.87%	$2,229
68	FY 2021 Net Incremental times rate difference				$126,088	* 2.94%	$3,709	$123,102	* 2.87%	$3,534
69	FY 2022 Net Adds times rate difference							$66,457	* 2.87%	$1,908
70	Total ISR Property Tax Recovery			$1,284			$2,099			$2,437

The Narragansett Electric Company
d/b/a Rhode Island Energy
Forecasted CY 2024 ISR Property Tax Recovery Adjustment 3 (continued)
(000s)

		(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)
		Cumulative Increm. ISR Prop. Tax for FY2023-NG			Cumulative Increm. ISR Prop. Tax for CY23-PPL			Cumulative Increm. ISR Prop. Tax for CY2024-PPL		
71	Incremental ISR Additions		$105,264			$83,460			$151,862	
72	Book Depreciation: base allowance on ISR eligible plant		($49,907)			($49,907)			($49,907)	
73	Book Depreciation: current year ISR additions		($1,422)			($757)			($1,836)	
74	COR		$16,300			$14,007			$13,529	
75	Net Plant Additions		$70,235			$46,803			$113,648	
76	RY Effective Tax Rate		3.66%			3.66%			3.66%	
77	ISR Property Tax Recovery on non-ISR									
78	ISR Year Effective Tax Rate	2.94%			2.87%			2.87%		
79	RY Effective Tax Rate	3.66%	-0.72%		3.66%	-0.79%		3.66%	-0.79%	
80	RY Effective Tax Rate 7 mos for FY 2019									
81	RY Net Plant times Rate Difference	$833,223	* -0.72%	($6,016)	$833,223	* -0.79%	($6,607)	$833,223	* -0.79%	($6,607)
82	Non-ISR plant times rate difference	($8,269)	* -0.72%	$60	($10,269)	* -0.79%	$81	($12,269)	* -0.79%	$97
83	FY 2018 Net Incremental times rate difference	$15,478	* 2.94%	$455	$14,931	* 2.87%	$429	$14,202	* 2.87%	$408
84	FY 2019 Net Incremental times rate difference	$28,015	* 2.94%	$824	$26,611	* 2.87%	$764	$23,566	* 2.87%	$677
85	FY 2020 Net Incremental times rate difference	$75,504	* 2.94%	$2,221	$73,891	* 2.87%	$2,121	$71,740	* 2.87%	$2,060
86	FY 2021 Net Incremental times rate difference	$120,116	* 2.94%	$3,534	$117,876	* 2.87%	$3,384	$114,890	* 2.87%	$3,299
87	FY 2022 Net Adds times rate difference	$64,754	* 2.94%	$1,905	$63,476	* 2.87%	$1,822	$61,773	* 2.87%	$1,773
88	FY 2023-NG Net Adds times rate difference	$70,235	* 2.94%	$2,066	$68,102	* 2.87%	$1,955	$65,969	* 2.87%	$1,894
89	CY 2023-NG Net Adds times rate difference				$46,803	* 2.87%	$1,344	$44,968	* 2.87%	$1,291
90	FY 2024-NG Net Adds times rate difference							$113,648	* 2.87%	$3,263
91	Total ISR Property Tax Recovery			$5,050			$5,294			$8,154

Line Notes

1(a) - 15(h)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 20,
16(a) - 20(a)	=11(h) - 15(h)
16(b) - 16(d)	Docket No. 5098 Attachment 1C, Page 26 of 29, 16(b) to 16(d)
16(e)	Docket 5098, C. Att. 2, Sch 6-ELEC, P2: (L37(b) + L38(b)) +((, L 6(a) + Page 6 of 46, L 6(a)+Page 12 of 46, L(a)+, L6(a)) × 0.0316+Page 10 of 4633(d)+, L(b))/1000 + (L1(c)+L6(c)+L11(c))×0.0301+, L6(a) × 0.0316× 0.5)/1000+L16(c)×0.5×0.0301
16(f) - 17(g)	Docket No. 5098 Attachment 1C, Page 26 of 29, 16(f) to 17(g)
16(h)	Sum of Lines 16(a) through 16(g)
17(h)	Sum of Lines 17(a) through 17(g)
18(h)	=16(h)-17(h)
19(h)	Per Company's Book
20(h)	Line 19(h) ÷ 18(h)
21(a) - 25(a)	=16(h) - 20(h)
21(b)	Page 25 of 46, Line 3(a) through 3(c) / 1000
21(c)	Per Company's Book
21(d)	Line 21(b) + Line 21(c)
21(f), 22(f)	Per Company's Book
21(h)	Line21(a) + 21(d) + 21(f)
22(e)	Per Company's Book
22(h)	Line22(a) + 22(e) + 22(f) + 22(g)
23(h)	21(h)-22(h)

Line Notes

24(h)	Per Company's Book
25(h)	Line 24(h) ÷ 23(h)
36(a) - 52(i)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
53(j) - 70(o)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
53(q) - 67(r)	Docket No. 5098 Attachment 1C, Page 26 of 29, 38(j) to 50(k)
68(p)	=68(m) - (Page 16 of 46, Line 19(b) ÷ 1000
69(p)	=57(q)
68(q) - 69(q)	=60(p)
68(r) - 69(r)	=68(p) to 69(p) x 68(q) to 69(q)
70(r)	Sum of Lines 63(r) through 69(r)
71(t)	Page 25 of 46, Line 3(a) through 3(c) / 1000
72(t)	Page 25 of 46, Line 8(a) through 8(c) / 1000
73(t)	Page 25 of 46, Line 19(a) through 19(c) /1000
74(t)	Page 25 of 46, Line 10(a) through 10(c) / 1000
75(t)	Sum of Lines 71(t) through 74(t)
76(t)	=58(q)
78(s)	=25(h)

Line Notes

79(s)	=76(t)
79(t)	78(s) -79(s)
81(s)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000]
82(s)	=64(p) - 2000
83(s)	=65(p) - (Page 2 of 46, Line 19(i) / 1000
84(s)	=66(p) - (Page 6 of 46, Line 19(e) + Page 10 of 46, Line 33(o))/1000
85(s)	=67(p) - (Page 12 of 46, Line 19(d) through 19(f) / 1000
86(s)	=68(p) - (Page 16 of 46, Line 19(c) through 19(e) / 1000
87(s)	=69(p) - (Page 21 of 46, Line 19(b) through 19(d) / 1000
88(s)	=75(t)
81(t)-82(t)	=79(t)
83(t)-88(t)	=78(s)
81(u) - 88(u)	=81(s) to 88(s) x 81(t) to 88(t)
91(u)	Sum of Lines 81(u) through 88(u)

Compliance Attachment 2
Schedule 6-ELEC
Page 2 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric

For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense in Base Rates
(Continued)

Line No.		Description		Reference	Amount	Line	less non-ISR eligible plant	ISR Eligible Amount
				(a)	(b)		(c)	(d)
1		**Rate Year Depreciation Expense 12 Months Ended 08/31/19:**				1		
2		Total Utility Plant 08/31/18		Page 1, Line 31 + Line 35 + Line 36	$2,201,836,293	2	($39,763,450)	$2,162,072,843
3		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	3	$0	($627,567,742)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,574,268,551	4	($39,763,450)	$1,534,505,101
5						5		
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-ELEC, Page 6, Line 38	$77,541,000	6	($2,698,000)	$74,843,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($22,998,661)	7	$800,227	($22,198,434)
8						8		
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,628,810,891	9	($41,661,224)	$1,587,149,667
10						10		
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,601,539,721	11	($40,712,337)	$1,560,827,384
12						12		
13		Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	13		3.16%
14						14		
15		Book Depreciation Reserve 08/31/18		Page 1, Line 47	$678,772,079	15		
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$50,375,341	16		$49,322,145
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	17		($247,009)
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($7,963,461)	18		
19		Less: Retired Plant		Line 7	($22,998,661)	19		
20		Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$697,938,290	20		$49,075,136
21						21		
22		**Rate Year Depreciation Expense 12 Months Ended 08/31/20:**				22		
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$2,256,378,633	23	($41,661,224)	$2,214,717,409
24		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	24	$0	($627,567,742)
25		Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,628,810,891	25	($41,661,224)	$1,587,149,667
26						26		
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-ELEC, Page 5, Line 15(i)	$2,000,000	27	($2,000,000)	$0
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($593,200)	28	$593,200	$0
29						29		
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,630,217,691	30	($43,068,024)	$1,587,149,667
31						31		
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,629,514,291	32	($42,364,624)	$1,587,149,667
33						33		
34		Proposed Composite Rate %		Page 4, Line 18, Column (f)	3.15%	34		3.16%
35						35		
36		Book Depreciation Reserve 08/31/20		Line 20	$697,938,290	36		
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$51,255,262	37		$50,153,929
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	38		($247,009)
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($205,400)	39		
40		Less: Retired Plant		Line 28	($593,200)	40	7 mos FY20	12 mos
41		Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$748,147,943	41	$ 436,419,633	$49,906,920
42						42		
43		**Rate Year Depreciation Expense 12 Months Ended 08/31/21:**				43		
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$2,257,785,433	44	($43,068,024)	$2,214,717,409
45		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	45	$0	($627,567,742)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,630,217,691	46	($43,068,024)	$1,587,149,667
47						47		
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-ELEC, Page 5, Line 15(l)	$2,000,000	48	($2,000,000)	$0
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($593,200)	49	$593,200	$0
50						50		
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,631,624,491	51	($44,474,824)	$1,587,149,667
52						52		
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,630,921,091	53	($43,771,424)	$1,587,149,667
54						54		
55		Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	55		3.16%
56						56		
57		Book Depreciation Reserve 08/31/20		Line 41	$748,147,943	57		
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$51,299,512	58		$50,153,929
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	59		($247,009)
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($205,400)	60		
61		Less: Retired Plant		Line 49	($593,200)	61		
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$798,401,846	62		$49,906,920
63								
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		29.66%	Retirements			
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		10.27%	COR			
66								
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)				$51,008,253
68		Less: General Plant Depreciation (assuming add=retirement)		- Page 38 of 46, Line 66 (c)				($1,435,572)
69		Plus: Comm Equipment Depreciation		Page 38 of 46, sum of Lines 59 (c) through 61 (c)				$368,062
70		Total						$49,940,743
71		7 Months						x7/12
72		FY 2020 Depreciation Expense		Line 66 (d) ×7 ÷12				$29,132,100
73								
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)				$51,052,503
75		Less: General Plant Depreciation		- Page 38 of 46, Line 66 (c)				($1,435,572)
76		Plus: Comm Equipment Depreciation		Page 38 of 46, sum of Lines 59 (c) through 61 (c)				$368,062
77		Total						$49,984,993
78		FY 2021 Depreciation Expense		Line 66 (d) ×5 ÷12 + Line 73 (d) ×7 ÷12				$49,966,556

The Narragansett Electric Company
d/b/a Rhode Island Energy
21-Month Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Weighted Average Cost of Capital

Line No.		(a)	(b)	(c)	(d)	(e)
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		Ratio	Rate	Weighted Rate	Taxes	Return
3	Long Term Debt	49.95%	4.96%	2.48%		2.48%
4	Short Term Debt	0.76%	0.79%	0.01%		0.01%
5	Preferred Stock	0.15%	4.50%	0.01%		0.01%
6	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
7		100.00%		7.17%	2.51%	9.68%
8						
9	(d) - Column (c) x 35% divided by (1 - 35%)					
10						
11	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
12		Ratio	Rate	Weighted Rate	Taxes	Return
13	Long Term Debt	49.95%	4.96%	2.48%		2.48%
14	Short Term Debt	0.76%	0.79%	0.01%		0.01%
15	Preferred Stock	0.15%	4.50%	0.01%		0.01%
16	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
17		100.00%		7.17%	1.24%	8.41%
18						
19	(d) - Column (c) x 21% divided by (1 - 21%)					
20						
21	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
22		Ratio	Rate	Weighted Rate	Taxes	Return
23	Long Term Debt	48.35%	4.62%	2.23%		2.23%
24	Short Term Debt	0.60%	1.76%	0.01%		0.01%
25	Preferred Stock	0.10%	4.50%	0.00%		0.00%
26	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
27		100.00%		6.97%	1.26%	8.23%
28						
29	(d) - Column (c) x 21% divided by (1 - 21%)					
30						
31	FY18 Blended Rate		Line 7(e) x 75% + Line 17(e) x 25%			9.36%
32						
33	FY19 Blended Rate		Line 17 x 5 ÷ 12 + Line 27 x 7 ÷ 12			8.31%
34						
35	FY20 and after Rate		Line 27(e)			8.23%

The Narragansett Electric Company
d/b/a Rhode Island Energy
CY 2023 (9-Months) Incremental Capital Investment

Line No.			Calendar Year 2023 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in CY 2023 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	CY 2023 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 18, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$39,031,000**	**$0**	$39,031,000
	Discretionary Capital				
2	Cumulative FY 2023-NG Discretionary Capital ADDITIONS	Docket 4915 + Docket 4995 + Docket 5098	$575,271,351		
3	CY 2023 Discretionary Capital ADDITIONS	Section 2, Chart 18, Col 2	$44,429,000		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$619,700,351		
5	Cumulative FY 2023-NG Discretionary Capital SPENDING	Docket 4915 + Docket 4995 + Docket 5098	$614,292,033		
6	CY 2023 Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$81,154,000		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$695,446,033		
8	Cumulative FY 2023-NG Approved Discretionary Capital SPENDING	Docket 4915 + Docket 4995 + Docket 5098	$615,807,536		
9	CY 2023 Approved Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$81,154,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$696,961,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$619,700,351		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Docket No. 5098 -ISR Plan Reconciliation	$575,271,351		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$44,429,000**	**$0**	**$44,429,000**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$83,460,000**	**$0**	**$83,460,000**
15	Intangible Assets included in Total Allowed Discretionary Capital				$0
16	**Total Allowed Discretionary Capital Included in non-Intangible Rate Base Current Year**	Line 14 - Line 15			**$83,460,000**

The Narragansett Electric Company
d/b/a Rhode Island Energy
CY 2024 (12-Months) Incremental Capital Investment

Line No.			Calendar Year 2024 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in CY 2024 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	CY 2024 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 18, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$96,737,000**	**$0**	$96,737,000
	Discretionary Capital				
2	Cumulative CY 2023 Discretionary Capital ADDITIONS	Page 45 of 46, Line 4	$619,700,351		
3	CY 2024 Discretionary Capital ADDITIONS	Section 2, Chart 18, Col 2	$55,125,000		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$674,825,351		
5	Cumulative CY 2023 Discretionary Capital SPENDING	Page 45 of 46, Line 7	$695,446,033		
6	CY 2024 Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$88,187,000		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$783,633,033		
8	Cumulative CY 2023 Approved Discretionary Capital SPENDING	Page 45 of 46, Line 10	$696,961,536		
9	CY 2024 Approved Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$88,187,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$785,148,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$674,825,351		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Page 45 of 46, Line 11	$619,700,351		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$55,125,000**	**$0**	**$55,125,000**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$151,862,000**	**$0**	**$151,862,000**
15	Intangible Assets included in Total Allowed Discretionary Capital	Section 2, Chart 10, Column 2 note			$0
16	**Total Allowed Discretionary Capital Included in non-Intangible Rate Base Current Year**	Line 14 - Line 15			**$151,862,000**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the 21-Month Electric Plan
CY 2023 - April 2023-December 2023

Inputs

1	Tax Rate		**21.00%**	
	Gas and Distribution			
2	Long Term Debt		**48.350%**	
3	Short Term Debt		**0.600%**	
4	Preferred Stock		**0.100%**	
5	Debt Weighting	Lines 2+3+4	**49.050%**	
6	Equity Weighting	1 - Line 5	**50.950%**	
7	Long Term Debt Rate		**4.620%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.576%**	
10	Cost of Equity		**9.275%**	
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.2300%**	0.000039
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**6.970%**	
13	Rate Base - PPL (after purchase)	Page 3. Line 9, Column (c)	$ 192,691,864	9- Month April-December 2023
14	Rate Base - NG (before sale)	Page 3. Line 9, Column (f)	$ 179,085,993	9- Month April-December 2023
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ 13,605,872**	Elimination of Deferred Taxes

Distribution ROE Mechanics

Notes:

1. The sale of the business is treated as a sale of assets for income tax purposes causing the reversal of cumulative timing differences and a payment to the government of the amounts that had been recorded as deferred tax liabilities by National Grid ("NG").
2. PPL does not assume the interest-free liability of ADIT from NG because NG paid this tax liability to the government as a result of the sales transaction. As such, PPL has to replace the no-cost capital with other capital. This calculation assumes that the substitute for the eliminated DTL is debt and equity in the same proportion as stated in Lines 5 and 6.
3. The revenue credit for hold harmless is reflected on Line 23.
4. Line 28 reflects the goodwill tax deduction needed to hold customers harmless from the increased revenue requirement due to the rate base increase from the elimination of deferred taxes. Any tax deduction lower than the amount reflected on this line will not provide enough of a tax benefit to share with
5. Line 29 relects the cash tax benefit of the goodwill tax deduction and is recorded for GAAP reporting (not reflected for FERC reporting). There is not an income statement tax benefit since the goodwill tax deduction is a flip between current and deferred taxes. This amount grossed up for tax is the revenue credit reflected on Line 23.

9-Month April to December 2023 (CY 2023)

			Post-Acquisition Results for ISR Capital Adjustments through the Date of Acquisition	Results for ISR Capital Adjustments through the Date of Acquisition as if the Acqusition did not occur	Difference	
			(a)	(b)	(c) = (a) - (b)	
16	Rate Base after Acqusition	Line 13	192,691,864	192,691,864	-	
17	ADIT Adjustment	- Line 15	-	(13,605,872)	13,605,872	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**192,691,864**	**179,085,993**	**13,605,872**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,324,641	4,019,281	305,361	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	9,105,871	8,462,910	642,961	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,420,548	2,249,634	170,914	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**15,851,060**	**14,731,825**	**1,119,235**	
23	Revenue Adjustment for 9 Month CY 2023	- Line 15 * Line 11	(1,119,763)	-	(1,119,763)	Note 1
24	**Total Revenue**	**Lines 23 + 24**	**14,731,297**	**14,731,825**	**(528)**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,019,281	4,019,281	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,249,523	2,249,634	(111)	
27	**Net Income**	**Lines 24 - 25 - 26**	**8,462,493**	**8,462,910**	**(417)**	

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * Line 1 / (1-Line 1)	4,212,443
29	Cash Tax Benefit at 21%	Line 28 * Line 1	884,613
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	1,119,763

Note 1: There is a slight variation in the calculated hold harmless amount in the ISR filing due to the roundings that are used to calculate the WACC in the ISR files

The Narragansett Electric Company
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the 21-Month Electric Plan
CY 2024 - January 2024-December 2024

	Inputs			
1	Tax Rate		**21.00%**	
	Gas and Distribution			
2	Long Term Debt		**48.350%**	
3	Short Term Debt		**0.600%**	
4	Preferred Stock		**0.100%**	
5	Debt Weighting	Lines 2+3+4	**49.050%**	
6	Equity Weighting	1 - Line 5	**50.950%**	
7	Long Term Debt Rate		**4.620%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.576%**	
10	Cost of Equity		**9.275%**	
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.2300%**	0.000039
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**6.970%**	
13	Rate Base - PPL (after purchase)	Page 3. Line 18, Column (c)	$ 243,996,605	12-Month CY 2024
14	Rate Base - NG (before sale)	Page 3. Line 18, Column (f)	$ 225,739,466	12-Month CY 2024
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ 18,257,139**	Elimination of Deferred Taxes

Distribution ROE Mechanics

Notes:
1. The sale of the business is treated as a sale of assets for income tax purposes causing the reversal of cumulative timing differences and a payment to the government of the amounts that had been recorded as deferred tax liabilities by National Grid ("NG").

2. PPL does not assume the interest-free liability of ADIT from NG because NG paid this tax liability to the government as a result of the sales transaction. As such, PPL has to replace the no-cost capital with other capital. This calculation assumes that the substitute for the eliminated DTL is debt and equity in the same proportion as stated in Lines 5 and 6.
3. The revenue credit for hold harmless is reflected on Line 23.
4. Line 28 reflects the goodwill tax deduction needed to hold customers harmless from the increased revenue requirement due to the rate base increase from the elimination of deferred taxes. Any tax deduction lower than the amount reflected on this line will not provide enough of a tax benefit to share with customers.

5. Line 29 relects the cash tax benefit of the goodwill tax deduction and is recorded for GAAP reporting (not reflected for FERC reporting). There is not an income statement tax benefit since the goodwill tax deduction is a flip between current and deferred taxes. This amount grossed up for tax is the revenue credit reflected on Line 23.

			12 Month January to December 2024 (CY 2024)			
			Post-Acquisition Results for ISR Capital Adjustments through the Date of Acquisition	**Results for ISR Capital Adjustments through the Date of Acquisition as if the Acqusition did not occur**	**Difference**	
			(a)	(b)	(c) = (a) - (b)	
16	Rate Base after Acqusition	Line 13	243,996,605	243,996,605	-	
17	ADIT Adjustment	- Line 15	-	(18,257,139)	18,257,139	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**243,996,605**	**225,739,466**	**18,257,139**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	5,476,089	5,066,339	409,750	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	11,530,334	10,667,572	862,762	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	3,065,026	2,835,684	229,342	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**20,071,449**	**18,569,595**	**1,501,854**	
23	Revenue Adjustment for 12 Month CY 2024	- Line 15 * Line 11	(1,502,563)	-	(1,502,563)	Note 1
24	**Total Revenue**	**Lines 23 + 24**	**18,568,886**	**18,569,595**	**(709)**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	5,066,339	5,066,339	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,835,535	2,835,684	(149)	
27	**Net Income**	**Lines 24 - 25 - 26**	**10,667,013**	**10,667,572**	**(560)**	

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * Line 1 / (1-Line 1)	5,652,497
29	Cash Tax Benefit at 21%	Line 28 * Line 1	1,187,024
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	1,502,563

Note 1: There is a slight variation in the calculated hold harmless amount in the ISR filing due to the roundings that are used to calculate the WACC in the ISR files.

The Narragansett Electric Company-Elec
d/b/a Rhode Island Energy
Average ISR Rate Base after Deferred Tax Proration

		Post-Acquisition (a)	Prorated (b)	Post-Acquisition Prorated for 9 months (c)		No Acquisition (d)	Prorated (e)	No Acquisition Prorated for 9 months (f)
1	**9 Months 2023**							
2	FY 2018	13,720,928	75%	10,290,696		14,210,458	75%	10,657,844
3	FY 2019	26,202,741	75%	19,652,056		23,119,123	75%	17,339,342
4	FY 2019 Intangible			959,516				549,220
5	FY 2020	45,012,582	75%	33,759,437		40,751,617	75%	30,563,713
6	FY 2021	67,969,857	75%	50,977,393		63,869,667	75%	47,902,250
7	FY 2022	42,281,005	75%	31,710,754		36,250,230	75%	27,187,673
8	FY 2023	60,456,018	75%	45,342,014		59,847,935	75%	44,885,951
9		255,643,131		192,691,864	Page 1, Line 13	238,049,030		179,085,993
10	**CY 2024**							
11	FY 2018	13,033,517	100%	13,033,517		13,627,235	100%	13,627,235
12	FY 2019	24,870,437	100%	24,870,437		21,889,628	100%	21,889,628
13	FY 2019 Intangible			841,792				390,556
14	FY 2020	42,677,636	100%	42,677,636		38,515,581	100%	38,515,581
15	FY 2021	64,480,498	100%	64,480,498		60,673,292	100%	60,673,292
16	FY 2022	39,983,442	100%	39,983,442		33,957,143	100%	33,957,143
17	FY 2023	58,109,283	100%	58,109,283		56,686,031	100%	56,686,031
18		243,154,813		243,996,605	Page 2, Line 13	225,348,910		225,739,466
19	Total 21-Month Plan	498,797,944		436,688,469		463,397,940		404,825,459

Section 6
Rate Design

Proposed FY2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 21 months beginning April 1, 2023)

		Residential A-16 / A-60 (a)	Small C&I C-06 (b)	General C&I G-02 (c)	Large Demand B-32 (d)	Large Demand G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	O&M Factor per kWh	$0.00276	$0.00267	$0.00240	$0.00121	$0.00121	$0.02096	$0.00048
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.07	n/a	n/a	n/a
(3)	CapEx kWh Charge	$0.00827	$0.00682	n/a	n/a	n/a	$0.01430	$0.00076
(4)	CapEx kW Charge	n/a	n/a	$2.22	$2.17	$2.17	n/a	n/a
(5)	Back-Up Service CapEx kW Charge	n/a	n/a	n/a	$0.21	n/a	n/a	n/a

(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Page 4, Line (4), applicable to backup service only
(3) Page 3, Line (6)
(4) Page 3, Line (8); Column (d) applicable to supplemental service only
(5) Page 4, Line (6), applicable to backup service only

The Narragansett Electric Company
FY24 Proposed Operations & Maintenance Factors
(for the 21 months beginning April 1, 2023)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2024 (21-Month) Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$ 29,645,000						
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$44,205	$22,620	$4,919	$7,563	$ 7,045	$2,036	$22
(3)	Percentage of Total	100.00%	51.17%	11.13%	17.11%	15.94%	4.61%	0.05%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$29,645,000	$15,169,549	$3,298,807	$5,071,941	$4,724,557	$1,365,394	$14,754
(5)	Forecasted kWh - April 2023 through December 2024	12,832,539,386	5,493,741,541	1,235,124,155	2,107,727,180	3,900,497,090	65,119,588	30,329,832
(6)	Proposed Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00276	$0.00267	$0.00240	$0.00121	$0.02096	$0.00048

(1) per Section 5: Attachment 1, Page 1, Line (4), Columns (b) and (c):

O&M Expense Component of Revenue Requirement (9 Months (Calendar Year 2023)):	$	13,203,000
O&M Expense Component of Revenue Requirement (12 Months (Calendar Year 2024)):	$	16,442,000
O&M Expense Component of Revenue Requirement (21 Months (FY 2024)):	$	29,645,000

(2) per R.I.P.U.C. 4770, Compliance Attachment 6 (August 16, 2018), (Schedule 1B), Page 3, Line 88
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places

The Narragansett Electric Company
FY24 Proposed CapEx Factors
(for the 21 months beginning April 1, 2023)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2024 (21-Month) Capital Investment Component of Revenue Requirement	$ 81,930,022						
(2)	Total Rate Base ($000s)	$729,511	$404,995	$75,009	$117,155	$123,849	$8,296	$208
(3)	Percentage of Total	100.00%	55.52%	10.28%	16.06%	16.98%	1.14%	0.03%
(4)	Allocated Revenue Requirement	$81,930,022	$45,484,199	$8,424,091	$13,157,481	$13,909,259	$931,664	$23,327
(5)	Forecasted kWh - April 2023 through December 2024	12,832,539,386	5,493,741,541	1,235,124,155	2,107,727,180	3,900,497,090	65,119,588	30,329,832
(6)	Proposed CapEx Factor - kWh charge		$0.00827	$0.00682	n/a	n/a	$0.01430	$0.00076
(7)	Forecasted kW - April 2023 through December 2024				5,921,035	6,387,842		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$2.22	$2.17	n/a	n/a

(1) per Section 5: Attachment 1, Page 1, Line (17), Columns (b) and (c) plus Line (19), Columns (b) and (c):

Total Net Capital Investment Component of Revenue Requirement (9 Months (Calendar Year 2023)):	$ 31,298,333
Total Net Capital Investment Component of Revenue Requirement (12 Months (Calendar Year 2024)):	$ 50,631,688
Total Net Capital Investment Component of Revenue Requirement (21 Months (FY 2024)):	$ 81,930,022

(2) R.I.P.U.C. 4770, Compliance Attachment 6 (August 16, 2018), (Schedule 1A), Page 1, Line 9
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B-32/G-32

The Narragansett Electric Company
Calculation of Operations & Maintenance and CapEx Factors
and Base Distribution Charge for Back-up Service Rates

		Large Demand B-32
	Operations & Maintenance Factors	
(1)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$4,724,557
(2)	Forecasted kW - April 2023 through December 2024	6,387,842
(3)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.73
(4)	Proposed Discounted O&M kW Factor Charge	$0.07
	CapEx Factors	
(5)	Proposed CapEx kW Factor Charge	$2.17
(6)	Proposed Discounted CapEx kW Factor Charge	$0.21

(1) Page 2, Line (4), Column (e)
(2) per Company forecasts
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x 0.10, truncated to 2 decimal places
(5) Page 3, Line (8), Column (e)
(6) Line (5) x 0.10, truncated to 2 decimal places

Section 7
Bill Impacts

Proposed FY2024 Electric Infrastructure,
Safety, and Reliability ("ISR") Plan

21-Month Electric ISR Plan
April 2023 – December 2024

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Monthly kWh (a)	Rates Effective October 1, 2022: Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Proposed Rates Effective April 1, 2023: Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	$ Increase (Decrease): Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Increase (Decrease) % of Total Bill: Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)	Percentage of Customers (r)
150	$19.82	$26.68	$1.94	$48.44	$20.19	$26.68	$1.95	$48.82	$0.37	$0.00	$0.01	$0.38	0.8%	0.0%	0.0%	0.8%	30.1%
300	$37.26	$53.36	$3.78	$94.40	$38.02	$53.36	$3.81	$95.19	$0.76	$0.00	$0.03	$0.79	0.8%	0.0%	0.0%	0.8%	12.9%
400	$48.89	$71.14	$5.00	$125.03	$49.90	$71.14	$5.04	$126.08	$1.01	$0.00	$0.04	$1.05	0.8%	0.0%	0.0%	0.8%	11.6%
500	$60.52	$88.93	$6.23	$155.68	$61.79	$88.93	$6.28	$157.00	$1.27	$0.00	$0.05	$1.32	0.8%	0.0%	0.0%	0.8%	9.6%
600	$72.15	$106.71	$7.45	$186.31	$73.67	$106.71	$7.52	$187.90	$1.52	$0.00	$0.07	$1.59	0.8%	0.0%	0.0%	0.9%	7.7%
700	$83.78	$124.50	$8.68	$216.96	$85.55	$124.50	$8.75	$218.80	$1.77	$0.00	$0.07	$1.84	0.8%	0.0%	0.0%	0.8%	19.0%
1,200	$141.93	$213.42	$14.81	$370.16	$144.97	$213.42	$14.93	$373.32	$3.04	$0.00	$0.12	$3.16	0.8%	0.0%	0.0%	0.9%	6.8%
2,000	$234.97	$355.70	$24.61	$615.28	$240.03	$355.70	$24.82	$620.55	$5.06	$0.00	$0.21	$5.27	0.8%	0.0%	0.0%	0.9%	2.3%

Line	Description		Rates Effective October 1, 2022 (s)	Proposed Rates Effective April 1, 2023 (t)	Line Item on Bill
(1)	Distribution Customer Charge		$0.00	$0.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$1.58	$1.58	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge		$0.00211	$\boxed{\$0.00276}$	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00000	$0.00000	
(7)	CapEx Factor Charge		$0.00639	$\boxed{\$0.00827}$	
(8)	CapEx Reconciliation Factor		($0.00089)	($0.00089)	
(9)	Revenue Decoupling Adjustment Factor		($0.00003)	($0.00003)	Distribution Energy Charge
(10)	Pension Adjustment Factor		($0.00045)	($0.00045)	
(11)	Storm Fund Replenishment Factor		$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor		$0.00007	$0.00007	
(13)	Performance Incentive Factor		$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor		$0.00238	$0.00238	
(15)	Long-term Contracting for Renewable Energy Charge		($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge		$0.00488	$0.00488	
(17)	Base Transmission Charge		$0.03524	$0.03524	
(18)	Transmission Adjustment Factor		$0.00095	$0.00095	Transmission Charge
(19)	Transmission Uncollectible Factor		$0.00046	$0.00046	
(20)	Base Transition Charge		$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment		$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge		$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge		$0.17149	$0.17149	
(24)	LRS Adjustment Factor		($0.00318)	($0.00318)	Supply Services Energy Charge
(25)	LRS Adminstrative Cost Adjustment Factor		$0.00233	$0.00233	
(26)	Renewable Energy Standard Charge		$0.00721	$0.00721	
	Line Item on Bill				
(27)	Customer Charge		$0.00	$0.00	
(28)	LIHEAP Enhancement Charge		$0.79	$0.79	
(29)	RE Growth Program		$1.58	$1.58	
(30)	Transmission Charge	kWh x	$0.03665	$0.03665	
(31)	Distribution Energy Charge	kWh x	$0.06338	$\boxed{\$0.06591}$	
(32)	Transition Charge	kWh x	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	kWh x	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	kWh x	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	kWh x	$0.17785	$0.17785	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

	Rates Effective October 1, 2022						Proposed Rates Effective April 1, 2023						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(a)	(b)	(c)	(d) = [(b)+(c)] x-.25	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.25	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$19.46	$26.68	($11.54)	$34.60	$1.44	$36.04	$19.84	$26.68	($11.63)	$34.89	$1.45	$36.34	$0.29	$0.00	$0.01	$0.30	0.8%	0.0%	0.0%	0.8%	32.1%
300	$36.55	$53.36	($22.48)	$67.43	$2.81	$70.24	$37.31	$53.36	($22.67)	$68.00	$2.83	$70.83	$0.57	$0.00	$0.02	$0.59	0.8%	0.0%	0.0%	0.8%	15.4%
400	$47.94	$71.14	($29.77)	$89.31	$3.72	$93.03	$48.95	$71.14	($30.02)	$90.07	$3.75	$93.82	$0.76	$0.00	$0.03	$0.79	0.8%	0.0%	0.0%	0.8%	12.5%
500	$59.33	$88.93	($37.07)	$111.19	$4.63	$115.82	$60.60	$88.93	($37.38)	$112.15	$4.67	$116.82	$0.96	$0.00	$0.04	$1.00	0.8%	0.0%	0.0%	0.9%	9.6%
600	$70.72	$106.71	($44.36)	$133.07	$5.54	$138.61	$72.24	$106.71	($44.74)	$134.21	$5.59	$139.80	$1.14	$0.00	$0.05	$1.19	0.8%	0.0%	0.0%	0.9%	7.2%
700	$82.11	$124.50	($51.65)	$154.96	$6.46	$161.42	$83.89	$124.50	($52.10)	$156.29	$6.51	$162.80	$1.33	$0.00	$0.05	$1.38	0.8%	0.0%	0.0%	0.9%	16.4%
1,200	$139.07	$213.42	($88.12)	$264.37	$11.02	$275.39	$142.11	$213.42	($88.88)	$266.65	$11.11	$277.76	$2.28	$0.00	$0.09	$2.37	0.8%	0.0%	0.0%	0.9%	5.2%
2,000	$230.21	$355.70	($146.48)	$439.43	$18.31	$457.74	$235.27	$355.70	($147.74)	$443.23	$18.47	$461.70	$3.80	$0.00	$0.16	$3.96	0.8%	0.0%	0.0%	0.9%	1.6%

	Rates Effective October 1, 2022 (w)	Proposed Rates Effective April 1, 2023 (x)	Line Item on Bill
(1) Distribution Customer Charge	$0.00	$0.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$1.58	$1.58	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00211	$\boxed{\$0.00276}$	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00000	
(7) CapEx Factor Charge	$0.00639	$\boxed{\$0.00827}$	
(8) CapEx Reconciliation Factor	($0.00089)	($0.00089)	
(9) Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(10) Pension Adjustment Factor	($0.00045)	($0.00045)	
(11) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12) Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13) Performance Incentive Factor	$0.00012	$0.00012	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00488	$0.00488	
(17) Base Transmission Charge	$0.03524	$0.03524	Transmission Charge
(18) Transmission Adjustment Factor	$0.00095	$0.00095	
(19) Transmission Uncollectible Factor	$0.00046	$0.00046	
(20) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21) Transition Adjustment	$0.00018	$0.00018	
(22) Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23) Last Resort Service Base Charge	$0.17149	$0.17149	Supply Services Energy Charge
(24) LRS Adjustment Factor	($0.00318)	($0.00318)	
(25) LRS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(26) Renewable Energy Standard Charge	$0.00721	$0.00721	
Line Item on Bill			
(27) Customer Charge	$0.00	$0.00	
(28) LIHEAP Enhancement Charge	$0.79	$0.79	
(29) RE Growth Program	$1.58	$1.58	
(30) Transmission Charge	$0.03665	$0.03665	
(31) Distribution Energy Charge	$0.06100	$\boxed{\$0.06353}$	
(32) Transition Charge	$0.00018	$0.00018	
(33) Energy Efficiency Programs	$0.01252	$0.01252	
(34) Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35) Supply Services Energy Charge	$0.17785	$0.17785	
(36) Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

	Rates Effective October 1, 2022						Proposed Rates Effective April 1, 2023						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d) = [(b)+(c)] x-.30	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$19.46	$26.68	($13.84)	$32.30	$1.35	$33.65	$19.84	$26.68	($13.96)	$32.56	$1.36	$33.92	$0.26	$0.00	$0.01	$0.27	0.8%	0.0%	0.0%	0.8%	32.1%
300	$36.55	$53.36	($26.97)	$62.94	$2.62	$65.56	$37.31	$53.36	($27.20)	$63.47	$2.64	$66.11	$0.53	$0.00	$0.02	$0.55	0.8%	0.0%	0.0%	0.8%	15.4%
400	$47.94	$71.14	($35.72)	$83.36	$3.47	$86.83	$48.95	$71.14	($36.03)	$84.06	$3.50	$87.56	$0.70	$0.00	$0.03	$0.73	0.8%	0.0%	0.0%	0.8%	12.5%
500	$59.33	$88.93	($44.48)	$103.78	$4.32	$108.10	$60.60	$88.93	($44.86)	$104.67	$4.36	$109.03	$0.89	$0.00	$0.04	$0.93	0.8%	0.0%	0.0%	0.9%	9.6%
600	$70.72	$106.71	($53.23)	$124.20	$5.18	$129.38	$72.24	$106.71	($53.69)	$125.26	$5.22	$130.48	$1.06	$0.00	$0.04	$1.10	0.8%	0.0%	0.0%	0.9%	7.2%
700	$82.11	$124.50	($61.98)	$144.63	$6.03	$150.66	$83.89	$124.50	($62.52)	$145.87	$6.08	$151.95	$1.24	$0.00	$0.05	$1.29	0.8%	0.0%	0.0%	0.9%	16.4%
1,200	$139.07	$213.42	($105.75)	$246.74	$10.28	$257.02	$142.11	$213.42	($106.66)	$248.87	$10.37	$259.24	$2.13	$0.00	$0.09	$2.22	0.8%	0.0%	0.0%	0.9%	5.2%
2,000	$230.21	$355.70	($175.77)	$410.14	$17.09	$427.23	$235.27	$355.70	($177.29)	$413.68	$17.24	$430.92	$3.54	$0.00	$0.15	$3.69	0.8%	0.0%	0.0%	0.9%	1.6%

		Rates Effective October 1, 2022 (w)	Proposed Rates Effective April 1, 2023 (x)	Line Item on Bill
(1)	Distribution Customer Charge	$0.00	$0.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$1.58	$1.58	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge	$0.00211	$\boxed{\$0.00276}$	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00000	
(7)	CapEx Factor Charge	$0.00639	$\boxed{\$0.00827}$	
(8)	CapEx Reconciliation Factor	($0.00089)	($0.00089)	
(9)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	Distribution Energy Charge
(10)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13)	Performance Incentive Factor	$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00488	$0.00488	
(17)	Base Transmission Charge	$0.03524	$0.03524	
(18)	Transmission Adjustment Factor	$0.00095	$0.00095	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00046	$0.00046	
(20)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment	$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge	$0.17149	$0.17149	
(24)	LRS Adjustment Factor	($0.00318)	($0.00318)	Supply Services Energy Charge
(25)	LRS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(26)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(27)	Customer Charge	$0.00	$0.00	
(28)	LIHEAP Enhancement Charge	$0.79	$0.79	
(29)	RE Growth Program	$1.58	$1.58	
(30)	Transmission Charge	$0.03665	$0.03665	
(31)	Distribution Energy Charge	$0.06100	$\boxed{\$0.06353}$	
(32)	Transition Charge	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	$0.17785	$0.17785	
(36)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

	Rates Effective October 1, 2022				Proposed Rates Effective April 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh (a)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)	of Customers (r)
250	$31.26	$45.70	$3.21	$80.17	$31.74	$45.70	$3.23	$80.67	$0.48	$0.00	$0.02	$0.50	0.6%	0.0%	0.0%	0.6%	56.3%
500	$59.28	$91.40	$6.28	$156.96	$60.26	$91.40	$6.32	$157.98	$0.98	$0.00	$0.04	$1.02	0.6%	0.0%	0.0%	0.6%	16.9%
1,000	$115.33	$182.79	$12.42	$310.54	$117.28	$182.79	$12.50	$312.57	$1.95	$0.00	$0.08	$2.03	0.6%	0.0%	0.0%	0.7%	8.1%
1,500	$171.38	$274.19	$18.57	$464.14	$174.31	$274.19	$18.69	$467.19	$2.93	$0.00	$0.12	$3.05	0.6%	0.0%	0.0%	0.7%	5.0%
2,000	$227.43	$365.58	$24.71	$617.72	$231.33	$365.58	$24.87	$621.78	$3.90	$0.00	$0.16	$4.06	0.6%	0.0%	0.0%	0.7%	13.6%

		Rates Effective October 1, 2022 (s)	Proposed Rates Effective April 1, 2023 (t)	Line Item on Bill
(1)	Distribution Customer Charge	$0.00	$0.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.44	$2.44	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04482	$0.04482	
(5)	Operating & Maintenance Expense Charge	$0.00211	$0.00267	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00000	
(7)	CapEx Factor Charge	$0.00543	$0.00682	
(8)	CapEx Reconciliation Factor	($0.00007)	($0.00007)	
(9)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	Distribution Energy Charge
(10)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13)	Performance Incentive Factor	$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor	$0.00238	$0.00238	
(15)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00488	$0.00488	
(17)	Base Transmission Charge	$0.03540	$0.03540	
(18)	Transmission Adjustment Factor	($0.00219)	($0.00219)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00036	$0.00036	
(20)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment	$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge	$0.16683	$0.16683	
(24)	LRS Adjustment Factor	$0.00665	$0.00665	Supply Services Energy Charge
(25)	LRS Adminstrative Cost Adjustment Factor	$0.00210	$0.00210	
(26)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(27)	Customer Charge	$0.00	$0.00	
(28)	LIHEAP Enhancement Charge	$0.79	$0.79	
(29)	RE Growth Program	$2.44	$2.44	
(30)	Transmission Charge	$0.03357	$0.03357	
(31)	Distribution Energy Charge	$0.06226	$0.06421	
(32)	Transition Charge	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	$0.18279	$0.18279	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (b). Line (7) per Section 6, Page 1, Line (3), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

			Rates Effective October 1, 2022				Proposed Rates Effective April 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)
20	200	4,000	$524.04	$731.16	$52.30	$1,307.50	$531.72	$731.16	$52.62	$1,315.50	$7.68	$0.00	$0.32	$8.00	0.6%	0.0%	0.0%	0.6%
50	200	10,000	$1,183.62	$1,827.90	$125.48	$3,137.00	$1,210.92	$1,827.90	$126.62	$3,165.44	$27.30	$0.00	$1.14	$28.44	0.9%	0.0%	0.0%	0.9%
100	200	20,000	$2,282.92	$3,655.80	$247.45	$6,186.17	$2,342.92	$3,655.80	$249.95	$6,248.67	$60.00	$0.00	$2.50	$62.50	1.0%	0.0%	0.0%	1.0%
150	200	30,000	$3,382.22	$5,483.70	$369.41	$9,235.33	$3,474.92	$5,483.70	$373.28	$9,331.90	$92.70	$0.00	$3.87	$96.57	1.0%	0.0%	0.0%	1.0%
20	300	6,000	$608.40	$1,096.74	$71.05	$1,776.19	$617.22	$1,096.74	$71.42	$1,785.38	$8.82	$0.00	$0.37	$9.19	0.5%	0.0%	0.0%	0.5%
50	300	15,000	$1,394.52	$2,741.85	$172.35	$4,308.72	$1,424.67	$2,741.85	$173.61	$4,340.13	$30.15	$0.00	$1.26	$31.41	0.7%	0.0%	0.0%	0.7%
100	300	30,000	$2,704.72	$5,483.70	$341.18	$8,529.60	$2,770.42	$5,483.70	$343.92	$8,598.04	$65.70	$0.00	$2.74	$68.44	0.8%	0.0%	0.0%	0.8%
150	300	45,000	$4,014.92	$8,225.55	$510.02	$12,750.49	$4,116.17	$8,225.55	$514.24	$12,855.96	$101.25	$0.00	$4.22	$105.47	0.8%	0.0%	0.0%	0.8%
20	400	8,000	$692.76	$1,462.32	$89.80	$2,244.88	$702.72	$1,462.32	$90.21	$2,255.25	$9.96	$0.00	$0.41	$10.37	0.4%	0.0%	0.0%	0.5%
50	400	20,000	$1,605.42	$3,655.80	$219.22	$5,480.44	$1,638.42	$3,655.80	$220.59	$5,514.81	$33.00	$0.00	$1.37	$34.37	0.6%	0.0%	0.0%	0.6%
100	400	40,000	$3,126.52	$7,311.60	$434.92	$10,873.04	$3,197.92	$7,311.60	$437.90	$10,947.42	$71.40	$0.00	$2.98	$74.38	0.7%	0.0%	0.0%	0.7%
150	400	60,000	$4,647.62	$10,967.40	$650.63	$16,265.65	$4,757.42	$10,967.40	$655.20	$16,380.02	$109.80	$0.00	$4.57	$114.37	0.7%	0.0%	0.0%	0.7%
20	500	10,000	$777.12	$1,827.90	$108.54	$2,713.56	$788.22	$1,827.90	$109.01	$2,725.13	$11.10	$0.00	$0.47	$11.57	0.4%	0.0%	0.0%	0.4%
50	500	25,000	$1,816.32	$4,569.75	$266.09	$6,652.16	$1,852.17	$4,569.75	$267.58	$6,689.50	$35.85	$0.00	$1.49	$37.34	0.5%	0.0%	0.0%	0.6%
100	500	50,000	$3,548.32	$9,139.50	$528.66	$13,216.48	$3,625.42	$9,139.50	$531.87	$13,296.79	$77.10	$0.00	$3.21	$80.31	0.6%	0.0%	0.0%	0.6%
150	500	75,000	$5,280.32	$13,709.25	$791.23	$19,780.80	$5,398.67	$13,709.25	$796.16	$19,904.08	$118.35	$0.00	$4.93	$123.28	0.6%	0.0%	0.0%	0.6%
20	600	12,000	$861.48	$2,193.48	$127.29	$3,182.25	$873.72	$2,193.48	$127.80	$3,195.00	$12.24	$0.00	$0.51	$12.75	0.4%	0.0%	0.0%	0.4%
50	600	30,000	$2,027.22	$5,483.70	$312.96	$7,823.88	$2,065.92	$5,483.70	$314.57	$7,864.19	$38.70	$0.00	$1.61	$40.31	0.5%	0.0%	0.0%	0.5%
100	600	60,000	$3,970.12	$10,967.40	$622.40	$15,559.92	$4,052.92	$10,967.40	$625.85	$15,646.17	$82.80	$0.00	$3.45	$86.25	0.5%	0.0%	0.0%	0.6%
150	600	90,000	$5,913.02	$16,451.10	$931.84	$23,295.96	$6,039.92	$16,451.10	$937.13	$23,428.15	$126.90	$0.00	$5.29	$132.19	0.5%	0.0%	0.0%	0.6%

		Rates Effective October 1, 2022 (r)	Proposed Rates Effective April 1, 2023 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$24.33	$24.33	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 10kW)	$6.90	$6.90	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 10kW)	$1.68	$2.22	
(6)	Distribution Charge (per kWh)	$0.00476	$0.00476	
(7)	Operating & Maintenance Expense Charge	$0.00183	$0.00240	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00000	
(9)	CapEx Reconciliation Factor	($0.00072)	($0.00072)	
(10)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	Distribution Energy Charge
(11)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(14)	Performance Incentive Factor	$0.00012	$0.00012	
(15)	Low Income Discount Recovery Factor	$0.00238	$0.00238	
(16)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00488	$0.00488	
(18)	Transmission Demand Charge	$4.97	$4.97	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01342	$0.01342	
(20)	Transmission Adjustment Factor	($0.00371)	($0.00371)	Transmission Adjustment
(21)	Transmission Uncollectible Factor	$0.00036	$0.00036	
(22)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(23)	Transition Adjustment	$0.00018	$0.00018	
(24)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(25)	Last Resort Service Base Charge	$0.16683	$0.16683	
(26)	LRS Adjustment Factor	$0.00665	$0.00665	Supply Services Energy Charge
(27)	LRS Adminstrative Cost Adjustment Factor	$0.00210	$0.00210	
(28)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(29)	Customer Charge	$145.00	$145.00	
(31)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$24.33	$24.33	
(32)	Transmission Adjustment	$0.01007	$0.01007	
(33)	Distribution Energy Charge	$0.01584	$0.01641	
(34)	Distribution Demand Charge	$8.58	$9.12	
(35)	Transmission Demand Charge	$4.97	$4.97	
(34)	Transition Charge	$0.00018	$0.00018	
(35)	Energy Efficiency Programs	$0.01252	$0.01252	
(36)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(37)	Supply Services Energy Charge	$0.18279	$0.18279	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (s): Line (5) per Section 6, Page 1, Line (4), Column (c). Line (7) per Section 6, Page 1, Line (1), Column (c). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

			Rates Effective October 1, 2022				Proposed Rates Effective April 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use	kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total
	(a)		(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (k) / (e)	(p) = (l) / (e)	(q) = (m) / (e)
200	200	40,000	$4,107.15	$10,422.93	$605.42	$15,135.50	$4,117.95	$10,422.93	$605.87	$15,146.75	$10.80	$0.00	$0.45	$11.25	0.1%	0.0%	0.0%	0.1%
750	200	150,000	$15,669.25	$39,086.00	$2,281.47	$57,036.72	$15,979.25	$39,086.00	$2,294.39	$57,359.64	$310.00	$0.00	$12.92	$322.92	0.5%	0.0%	0.0%	0.6%
1,000	200	200,000	$20,924.75	$52,114.67	$3,043.31	$76,082.73	$21,370.75	$52,114.67	$3,061.89	$76,547.31	$446.00	$0.00	$18.58	$464.58	0.6%	0.0%	0.0%	0.6%
1,500	200	300,000	$31,435.75	$78,172.00	$4,566.99	$114,174.74	$32,153.75	$78,172.00	$4,596.91	$114,922.66	$718.00	$0.00	$29.92	$747.92	0.6%	0.0%	0.0%	0.7%
2,500	200	500,000	$52,457.75	$130,286.67	$7,614.35	$190,358.77	$53,719.75	$130,286.67	$7,666.93	$191,673.35	$1,262.00	$0.00	$52.58	$1,314.58	0.7%	0.0%	0.0%	0.7%
5,000	200	1,000,000	$105,012.75	$260,573.33	$15,232.75	$380,818.83	$107,634.75	$260,573.33	$15,342.00	$383,550.08	$2,622.00	$0.00	$109.25	$2,731.25	0.7%	0.0%	0.0%	0.7%
7,500	200	1,500,000	$157,567.75	$390,860.00	$22,851.16	$571,278.91	$161,549.75	$390,860.00	$23,017.07	$575,426.82	$3,982.00	$0.00	$165.91	$4,147.91	0.7%	0.0%	0.0%	0.7%
10,000	200	2,000,000	$210,122.75	$521,146.67	$30,469.56	$761,738.98	$215,464.75	$521,146.67	$30,692.14	$767,303.56	$5,342.00	$0.00	$222.58	$5,564.58	0.7%	0.0%	0.0%	0.7%
20,000	200	4,000,000	$420,342.75	$1,042,293.33	$60,943.17	$1,523,579.25	$431,124.75	$1,042,293.33	$61,392.42	$1,534,810.50	$10,782.00	$0.00	$449.25	$11,231.25	0.7%	0.0%	0.0%	0.7%
200	300	60,000	$5,004.35	$15,634.40	$859.95	$21,498.70	$5,020.55	$15,634.40	$860.62	$21,515.57	$16.20	$0.00	$0.67	$16.87	0.1%	0.0%	0.0%	0.1%
750	300	225,000	$19,033.75	$58,629.00	$3,235.95	$80,898.70	$19,364.00	$58,629.00	$3,249.71	$81,242.71	$330.25	$0.00	$13.76	$344.01	0.4%	0.0%	0.0%	0.4%
1,000	300	300,000	$25,410.75	$78,172.00	$4,315.95	$107,898.70	$25,883.75	$78,172.00	$4,335.66	$108,391.41	$473.00	$0.00	$19.71	$492.71	0.4%	0.0%	0.0%	0.5%
1,500	300	450,000	$38,164.75	$117,258.00	$6,475.95	$161,898.70	$38,923.25	$117,258.00	$6,507.55	$162,688.80	$758.50	$0.00	$31.60	$790.10	0.5%	0.0%	0.0%	0.5%
2,500	300	750,000	$63,672.75	$195,430.00	$10,795.95	$269,898.70	$65,002.25	$195,430.00	$10,851.34	$271,283.59	$1,329.50	$0.00	$55.39	$1,384.89	0.5%	0.0%	0.0%	0.5%
5,000	300	1,500,000	$127,442.75	$390,860.00	$21,595.95	$539,898.70	$130,199.75	$390,860.00	$21,710.82	$542,770.57	$2,757.00	$0.00	$114.87	$2,871.87	0.5%	0.0%	0.0%	0.5%
7,500	300	2,250,000	$191,212.75	$586,290.00	$32,395.95	$809,898.70	$195,397.25	$586,290.00	$32,570.30	$814,257.55	$4,184.50	$0.00	$174.35	$4,358.85	0.5%	0.0%	0.0%	0.5%
10,000	300	3,000,000	$254,982.75	$781,720.00	$43,195.95	$1,079,898.70	$260,594.75	$781,720.00	$43,429.78	$1,085,744.53	$5,612.00	$0.00	$233.83	$5,845.83	0.5%	0.0%	0.0%	0.5%
20,000	300	6,000,000	$510,062.75	$1,563,440.00	$86,395.95	$2,159,898.70	$521,384.75	$1,563,440.00	$86,867.70	$2,171,692.45	$11,322.00	$0.00	$471.75	$11,793.75	0.5%	0.0%	0.0%	0.5%
200	400	80,000	$5,901.55	$20,845.87	$1,114.48	$27,861.90	$5,923.15	$20,845.87	$1,115.38	$27,884.40	$21.60	$0.00	$0.90	$22.50	0.1%	0.0%	0.0%	0.1%
750	400	300,000	$22,398.25	$78,172.00	$4,190.43	$104,760.68	$22,748.75	$78,172.00	$4,205.03	$105,125.78	$350.50	$0.00	$14.60	$365.10	0.3%	0.0%	0.0%	0.3%
1,000	400	400,000	$29,896.75	$104,229.33	$5,588.59	$139,714.67	$30,396.75	$104,229.33	$5,609.42	$140,235.50	$500.00	$0.00	$20.83	$520.83	0.4%	0.0%	0.0%	0.4%
1,500	400	600,000	$44,893.75	$156,344.00	$8,384.91	$209,622.66	$45,692.75	$156,344.00	$8,418.20	$210,454.95	$799.00	$0.00	$33.29	$832.29	0.4%	0.0%	0.0%	0.4%
2,500	400	1,000,000	$74,887.75	$260,573.33	$13,977.55	$349,438.63	$76,284.75	$260,573.33	$14,035.75	$350,893.83	$1,397.00	$0.00	$58.20	$1,455.20	0.4%	0.0%	0.0%	0.4%
5,000	400	2,000,000	$149,872.75	$521,146.67	$27,959.14	$698,978.56	$152,764.75	$521,146.67	$28,079.64	$701,991.06	$2,892.00	$0.00	$120.50	$3,012.50	0.4%	0.0%	0.0%	0.4%
7,500	400	3,000,000	$224,857.75	$781,720.00	$41,940.74	$1,048,518.49	$229,244.75	$781,720.00	$42,123.53	$1,053,088.28	$4,387.00	$0.00	$182.79	$4,569.79	0.4%	0.0%	0.0%	0.4%
10,000	400	4,000,000	$299,842.75	$1,042,293.33	$55,922.34	$1,398,058.42	$305,724.75	$1,042,293.33	$56,167.42	$1,404,185.50	$5,882.00	$0.00	$245.08	$6,127.08	0.4%	0.0%	0.0%	0.4%
20,000	400	8,000,000	$599,782.75	$2,084,586.67	$111,848.73	$2,796,218.15	$611,644.75	$2,084,586.67	$112,342.98	$2,808,574.40	$11,862.00	$0.00	$494.25	$12,356.25	0.4%	0.0%	0.0%	0.4%
200	500	100,000	$6,798.75	$26,057.33	$1,369.00	$34,225.08	$6,825.75	$26,057.33	$1,370.13	$34,253.21	$27.00	$0.00	$1.13	$28.13	0.1%	0.0%	0.0%	0.1%
750	500	375,000	$25,762.75	$97,715.00	$5,144.91	$128,622.66	$26,133.50	$97,715.00	$5,160.35	$129,008.85	$370.75	$0.00	$15.44	$386.19	0.3%	0.0%	0.0%	0.3%
1,000	500	500,000	$34,382.75	$130,286.67	$6,861.23	$171,530.65	$34,909.75	$130,286.67	$6,883.18	$172,079.60	$527.00	$0.00	$21.95	$548.95	0.3%	0.0%	0.0%	0.3%
1,500	500	750,000	$51,622.75	$195,430.00	$10,293.87	$257,346.62	$52,462.25	$195,430.00	$10,328.84	$258,221.09	$839.50	$0.00	$34.97	$874.47	0.3%	0.0%	0.0%	0.3%
2,500	500	1,250,000	$86,102.75	$325,716.67	$17,159.14	$428,978.56	$87,567.25	$325,716.67	$17,220.16	$430,504.08	$1,464.50	$0.00	$61.02	$1,525.52	0.3%	0.0%	0.0%	0.4%
5,000	500	2,500,000	$172,302.75	$651,433.33	$34,322.34	$858,058.42	$175,329.75	$651,433.33	$34,448.46	$861,211.54	$3,027.00	$0.00	$126.12	$3,153.12	0.4%	0.0%	0.0%	0.4%
7,500	500	3,750,000	$258,502.75	$977,150.00	$51,485.54	$1,287,138.29	$263,092.25	$977,150.00	$51,676.76	$1,291,919.01	$4,589.50	$0.00	$191.22	$4,780.72	0.4%	0.0%	0.0%	0.4%
10,000	500	5,000,000	$344,702.75	$1,302,866.67	$68,648.73	$1,716,218.15	$350,854.75	$1,302,866.67	$68,905.06	$1,722,626.48	$6,152.00	$0.00	$256.33	$6,408.33	0.4%	0.0%	0.0%	0.4%
20,000	500	10,000,000	$689,502.75	$2,605,733.33	$137,301.51	$3,432,537.59	$701,904.75	$2,605,733.33	$137,818.26	$3,445,456.34	$12,402.00	$0.00	$516.75	$12,918.75	0.4%	0.0%	0.0%	0.4%
200	600	120,000	$7,695.95	$31,268.80	$1,623.53	$40,588.28	$7,728.35	$31,268.80	$1,624.88	$40,622.03	$32.40	$0.00	$1.35	$33.75	0.1%	0.0%	0.0%	0.1%
750	600	450,000	$29,127.25	$117,258.00	$6,099.39	$152,484.64	$29,518.25	$117,258.00	$6,115.68	$152,891.93	$391.00	$0.00	$16.29	$407.29	0.3%	0.0%	0.0%	0.3%
1,000	600	600,000	$38,868.75	$156,344.00	$8,133.87	$203,346.62	$39,422.75	$156,344.00	$8,156.95	$203,923.70	$554.00	$0.00	$23.08	$577.08	0.3%	0.0%	0.0%	0.3%
1,500	600	900,000	$58,351.75	$234,516.00	$12,202.82	$305,070.57	$59,231.75	$234,516.00	$12,239.49	$305,987.24	$880.00	$0.00	$36.67	$916.67	0.3%	0.0%	0.0%	0.3%
2,500	600	1,500,000	$97,317.75	$390,860.00	$20,340.74	$508,518.49	$98,849.75	$390,860.00	$20,404.57	$510,114.32	$1,532.00	$0.00	$63.83	$1,595.83	0.3%	0.0%	0.0%	0.3%
5,000	600	3,000,000	$194,732.75	$781,720.00	$40,685.53	$1,017,138.28	$197,894.75	$781,720.00	$40,817.28	$1,020,432.03	$3,162.00	$0.00	$131.75	$3,293.75	0.3%	0.0%	0.0%	0.3%
7,500	600	4,500,000	$292,147.75	$1,172,580.00	$61,030.33	$1,525,758.08	$296,939.75	$1,172,580.00	$61,229.99	$1,530,749.74	$4,792.00	$0.00	$199.66	$4,991.66	0.3%	0.0%	0.0%	0.3%
10,000	600	6,000,000	$389,562.75	$1,563,440.00	$81,375.12	$2,034,377.87	$395,984.75	$1,563,440.00	$81,642.70	$2,041,067.45	$6,422.00	$0.00	$267.58	$6,689.58	0.3%	0.0%	0.0%	0.3%
20,000	600	12,000,000	$779,222.75	$3,126,880.00	$162,754.29	$4,068,857.04	$792,164.75	$3,126,880.00	$163,293.54	$4,082,338.29	$12,942.00	$0.00	$539.25	$13,481.25	0.3%	0.0%	0.0%	0.3%

	Rates Effective October 1, 2022	Proposed Rates Effective April 1, 2023	Line Item on Bill
	(r)	(s)	
(1) Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$197.96	$197.96	RE Growth Program
(4) Base Distribution Demand Charge (per kW > 200kW)	$5.30	$5.30	Distribution Demand Charge
(5) CapEx Factor Demand Charge (per kW > 200kW)	$1.68	$2.17	
(6) Distribution Charge (per kWh)	$0.00430	$0.00430	
(7) Operating & Maintenance Expense Charge	$0.00094	$0.00121	
(8) Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00000	
(9) CapEx Reconciliation Factor	($0.00045)	($0.00045)	
(10) Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	Distribution Energy Charge
(11) Pension Adjustment Factor	($0.00045)	($0.00045)	
(12) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13) Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(14) Performance Incentive Factor	$0.00012	$0.00012	
(15) Low Income Discount Recovery Factor	$0.00238	$0.00238	
(16) Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00488	$0.00488	
(18) Transmission Demand Charge	$5.07	$5.07	Transmission Demand Charge
(19) Base Transmission Charge	$0.01442	$0.01442	
(20) Transmission Adjustment Factor	($0.00093)	($0.00093)	Transmission Adjustment
(21) Transmission Uncollectible Factor	$0.00034	$0.00034	
(22) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(23) Transition Adjustment	$0.00018	$0.00018	
(24) Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(25) Last Resort Service Base Charge	$0.24693	$0.24693	
(26) LRS Adjustment Factor	$0.00375	$0.00375	Supply Services Energy Charge
(27) LRS Adminstrative Cost Adjustment Factor	$0.00268	$0.00268	
(28) Renewable Energy Standard Charge	$0.00721	$0.00721	
Line Item on Bill			
(29) Customer Charge	$1,100.00	$1,100.00	
(30) LIHEAP Enhancement Charge	$0.79	$0.79	
(31) RE Growth Program	$197.96	$197.96	
(32) Transmission Adjustment	$0.01383	$0.01383	
(33) Distribution Energy Charge	$0.01476	$0.01503	
(34) Distribution Demand Charge	$6.98	$7.47	
(35) Transmission Demand Charge	$5.07	$5.07	
(34) Transition Charge	$0.00018	$0.00018	
(35) Energy Efficiency Programs	$0.01252	$0.01252	
(36) Renewable Energy Distribution Charge	$0.00357	$0.00357	
(37) Supply Services Energy Charge	$0.26057	$0.26057	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022
Column (s): Line (5) per Section 6, Page 1, Line (4), Column (e). Line (7) per Section 6, Page 1, Line (1), Column (e). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2022

JOINT PRE-FILED DIRECT TESTIMONY

OF

STEPHANIE A. BRIGGS

JEFFREY D. OLIVEIRA

ANDREW W. ELMORE

AND

NATALIE HAWK

Table of Contents

I. Introduction

Stephanie A. Briggs

Q. Please state your full name and business address.

A. My name is Stephanie A. Briggs, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Please state your position and responsibilities in that position.

A. I am employed by PPL Services Corporation ("Services Corporation") as a Senior Manager of Revenue and Rates. The Services Corporation provides administrative, management and support services to PPL Corporation ("PPL") and its subsidiary companies, including The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"). My current duties include responsibility for revenue requirement and rates calculations for the Company.

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Arts degree in Accounting from Bryant College. In 2004, I joined National Grid USA Service Company, Inc. ("National Grid Service Company") as a Senior Analyst in the Accounting Department. In this position, I was responsible for supporting the books and records of one of National Grid USA's ("National Grid") New York affiliates. In 2009, I joined National Grid Service Company's Regulatory Accounting Group. In 2011, I was promoted to Lead Specialist for Revenue Requirements supporting New York. In 2017, I was promoted to Director of Revenue Requirements for New York. In July 2020, I became Director of Revenue Requirements for New England. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of the Company from National Grid USA (the "Acquisition") at which time I began working in my current position.

Q. Have you previously filed testimony or testified before the Rhode Island Public Utilities Commission (Commission)?

A. Yes. I provided pre-filed direct testimony in numerous dockets including the Company's 2022 Annual Retail Rate Filing, Docket No. 5234, the Company's 2021 Performance Incentive Mechanism Factor Filing, as part of Docket No. 4770, the Fiscal Year 2022 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing, Docket No. 5098, the Company's 2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG and most recently in the Company's Advanced Metering Functionality Business Case, Docket No. 22-49-EL. I also have testified before the Massachusetts Department of Public Utilities and New York Public Service Commission on behalf of the Company's former affiliates as a revenue requirement witness in various proceedings.

Jeffrey D. Oliveira

Q. Please state your full name and business address.

A. My name is Jeffrey D. Oliveira, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Please state your position and responsibilities in that position.

A. I am employed by the Services Corporation as a Regulatory Programs Specialist. My current duties include leading the revenue requirement analyses and modeling that support regulatory filings, regulatory strategies, and rate cases for the Company.

Q. Please describe your education and professional experience.

A. In 2000, I earned an associate degree in Business Administration from Bristol Community College in Fall River, Massachusetts. I was employed by National Grid Service Company and its predecessor companies from 1999-2022. From 1999 through 2000, I was employed by Fall River Gas Company as a Staff Accountant. In 2001, after Fall River Gas Company merged with Southern Union Company, I continued as a Staff Accountant with increased responsibilities. In August of 2006, the Company acquired the Rhode Island gas distribution assets of Southern Union Company at which time I joined the National Grid Service Company as a Senior Accounting Analyst. In January 2009, I became a Senior Revenue Requirement Analyst in National Grid Service Company's Strategy and Regulation Department. In July 2011, I was promoted to Lead Revenue

Requirement Analyst in the New England Revenue Requirements group of the New England Regulatory Department of the National Grid Service Company. Upon closing of the Acquisition, I began working in my current position.

Q. Have you previously filed testimony or testified before the PUC?

A. Yes. I testified before the PUC in support of the Company's filings in m proceedings as follows: 2022 Last Resort Service Rate Filing, Docket No. 4978; 2022 Renewable Energy Growth Factor Filing, Docket No. 22-04-REG; 2022 Annual Retail Rate Filing Docket 5234; Joint Petition of National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") filed February 23, 2022 relating to the Storm Contingency Fund Replenishment, Docket No. 4686; 2021 Distribution Adjustment Charge Filing, Docket No. 5165; 2021 Pension Adjustment Factor Filing, Docket No. 5179; 2020 Distribution Adjustment Charge Filing, Docket No. 5040; 2020 Pension Adjustment Factor Filing, Docket No. 5054; 2019 Distribution Adjustment Charge Filing, Docket No. 4955; 2019 Pension Adjustment Factor Filing,, Docket No. 4958; 2018 Distribution Adjustment Charge Filing, Docket No. 4846; 2018 Pension Adjustment Factor Filing, Docket No. 4855; and again in Docket No. 4686, in support of the Joint Proposal and Settlement submitted by the Company and the Division dated September 25, 2017 pertaining to the operation of the Storm Contingency Fund. I have also submitted pre-filed testimony to the Massachusetts Department of Public Utilities on behalf of the Company's affiliates, Massachusetts Electric Company, and Nantucket

Electric Company, as a revenue requirement witness in annual pension adjustment mechanism proceedings.

<u>Andrew W. Elmore</u>

Q. Please state your full name and business address.

A. My name is Andrew W. Elmore, and my business address is 2 North 9th Street, Allentown, Pennsylvania 18049.

Q. Please state your position and your responsibilities within that position.

A. I am employed by the Services Corporation as the Vice President - Tax. The Services Corporation provides, among other things, tax services to PPL and its subsidiary companies, including Rhode Island Energy. My current duties include responsibility for, and oversight of, all tax matters of the PPL group of companies.

Q. Please describe your education and professional experience

A. In 1989, I received a Bachelor of Arts degree in French and Political Science from the University of Massachusetts in Boston. In 1993, I obtained a law degree from the University of Kentucky College of Law. I was formerly a member of the Rhode Island Bar Association and am currently a member of the Massachusetts Bar Association. In 1993, I joined the law firm of Powers, Kinder and Kenney, based in Providence Rhode Island, as an associate. I then joined Arthur Andersen as an International Tax Consultant in 1996. In turn, I joined the firm Deloitte & Touche as an International Tax Manager in 2000. In 2004, I accepted a position at United Technologies Corporation as an International Tax Manager. I subsequently worked as the Director of International Tax for Zimmer Corporation in Indiana from 2006 until 2011, at which time I joined PPL as the Director of International Tax. In 2016, I assumed the role of Director of Tax Planning and Compliance. I was then promoted to the position of Vice President – Tax in 2020.

Q. Have you previously filed testimony or testified before the PUC or any other jurisdiction?

A. No.

<u>Natalie Hawk</u>

Q. Please state your full name and business address.

A. My name is Natalie Hawk, and my business address is 2 North Ninth Street, Allentown, Pennsylvania 18101.

Q. Please state your position and your responsibilities within that position.

A. I am employed by the Services Corporation as the Director of tax accounting and reporting. My current responsibilities are to oversee the accounting and reporting of income and non-income taxes under U.S. Generally Accepted Accounting Principles and the FERC Uniform System of Accounts and support regulatory rate filings from a tax perspective.

Q. Please describe your education and professional experience

A. In 1992, I received a Bachelor of Science in Business Administration degree with a major in Accounting from Kutztown University. In 1998, I received a Master's in Business Administration degree from Lehigh University. In 1993, I started my career as a first-year Accountant in the Accounting Department at Metropolitan Edison Company, a wholly owned subsidiary of GPU, Inc. GPU is a public utility holding company based in New Jersey that was acquired by First Energy in 2001. I held various accounting roles in Accounting Operations, the Tax Department and Plant Accounting. In 2001, I accepted a position at Services Corporation as an Accounting Analyst in the Tax Department. My responsibilities included accounting for income and non-income taxes, and I later became involved in financial tax reporting for SEC and regulatory purposes, preparing tax information and providing guidance on tax matters for rate cases, formula rates and other rate mechanisms. I was promoted to Team Leader in 2004, 1st-level Manager in 2011, 2nd-level Manager in 2015 and to my current position as Tax Director in 2021.

Q. Have you previously filed testimony or testified before the PUC or any other jurisdiction?

A. No.

II. Purpose of Joint Testimony

Q. What is the purpose of your joint testimony?

A. The purpose of this joint testimony is to sponsor Section 5 of the proposed fiscal year ("FY") 2024 21-Month Electric ISR Plan ("Electric ISR Plan" or "Plan"), which covers the period April 1, 2023 through December 31, 2024). Section 5 describes the calculation of the Company's revenue requirement for the nine-month period from April 1, 2023 through December 31, 2023 ("CY 2023") and the twelve-month period from January 1, 2024 through December 31, 2024 ("CY 2024") in Attachment 1 of that section. The revenue requirement is based on the 21-month Electric ISR Plan operation and maintenance (O&M) expenses and capital investment, which are described in the joint pre-filed direct testimony of Witnesses Nicole Begnal, Christopher Rooney, Kathy Castro, Ryan Constable, and Wanda Reder. We also describe the impact of the sale of the Company to PPL Rhode Island Holdings, LLC ("PPL Rhode Island")[1] on the FY 2024 21-month revenue requirement. The Company's FY 2023 Electric ISR Plan for the period April 1, 2022 through March 31, 2023 approved in Docket No. 5209 is referenced in this section as "FY 2023-NG."

[1] PPL Rhode Island Holdings, LLC is a wholly owned indirect subsidiary of PPL Corporation.

III. <u>Electric ISR Plan Revenue Requirement</u>

Q. Please summarize the revenue requirement for the Company's 21-Month FY 2024 Electric ISR Plan.

A. As shown on Section 5, Attachment 1, Page 1, Column (b), the Company's CY 2023 Electric ISR Plan revenue requirement totals $44,501,333, or a decrease of $5,219,991 below the amount currently being billed for the Electric ISR Plan. The CY 2023 Plan revenue requirement consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and Other Programs, (2) the Company's capital investment in electric utility infrastructure, (3) the CY 2023 Property Tax Recovery Adjustment, and (4) an adjustment for the tax hold harmless impact on ISR rate base as will be described below. Lines 1, 2 and 3 of Column (b) reflect the forecasted CY 2023 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,595,000, $774,000, and $1,834,000 respectively. The Electric ISR Plan includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program ("Contact Voltage Program"), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Commission in Docket No. 4237. Contact Voltage Program costs are included in the $774,000 of I&M expenses referred to above. Prior ISR proposals included a reduction to I&M expenses related to Contact Voltage Program costs that were being recovered in base distribution rates in RIPUC Docket No. 4323; however, this reduction is no longer required because in the Company's most recent general rate case in RIPUC Docket No. 4770, Contact Voltage Program costs were excluded from the cost of service to be recovered in base distribution rates, effective September 1, 2018.

Additionally, as shown on Section 5, Attachment 1, Page 1, Column (c), the Company's CY 2024 Electric ISR Plan revenue requirement totals $67,073,688 or an incremental $22,572,355 over the CY 2023 revenue requirement. The CY 2024 Plan revenue requirement consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, the Company's Inspection and Maintenance ("I&M") program, and Other Programs, (2) the Company's capital investment in electric utility infrastructure, (3) the CY 2024 Property Tax Recovery Adjustment, and (4) an adjustment for the tax hold harmless impact on ISR rate base as will be described below. Lines 1, 2 and 3 of Column (b) reflect the forecasted CY 2024 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $13,436,000, $855,000, and $2,151,000, respectively. The Electric ISR Plan includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program ("Contact Voltage Program"), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Commission in Docket No. 4237. Contact Voltage Program costs are included in the $855,000 of I&M expenses referred to above. Prior ISR proposals included a reduction to I&M expenses related to Contact Voltage Program costs that were being recovered in base distribution rates in RIPUC Docket No. 4323; however, this reduction is no longer required because in the Company's most recent general rate case in RIPUC Docket No. 4770, Contact Voltage Program costs were excluded from the cost of service to be recovered in base rates, effective September 1, 2018.

Q. Did the Company calculate the 21-Month Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions?

A. Yes.

Q. Please explain the decrease of CY 2023 Electric ISR Plan revenue requirement over the amount currently being billed for Electric ISR Plan.

A. As mentioned above, the Company's CY 2023 Electric ISR Plan revenue requirement is $5,219,991 lower than the FY 2023-NG Electric ISR Plan revenue requirement. Of the total $44,501,333 revenue requirement in CY 2023, $25,072,283 in capital investment revenue requirement and $3,949,920 in property tax recovery adjustment are associated with incremental ISR Plan capital investment for FY 2018 through FY 2023-NG, which the PUC has approved in previous Electric ISR Plan or reconciliation filings. The decrease in the CY 2023 revenue requirement associated with previous fiscal years' capital investments compared to the approved FY 2023-NG Plan revenue requirement on that same investment totals $6,016,214 and is due 1) a decrease in actual FY 2022 incremental capital investment compared to the amounts included in the FY 2023-NG plan revenue requirement for FY 2022, 2) an increase to vintage rate base affected by the sale as described below, 3) a decrease in revenue requirement by the proration that CY 2023 is only a nine-month revenue requirement compared to FY 2023-NG which was a 12-month period, and 4) an increase due to the half-year convention applied in the year of installation. The CY 2023 revenue requirement on vintage year FY 2023-NG incremental ISR Plan capital investment increased by $1,920,591 from the FY 2023-NG revenue requirement on the same investment. The movement in the property tax recovery adjustment related to prior years' investment as well as rate base embedded in current distribution rates is a decrease of $1,543,907 The CY 2023 proposed incremental ISR Plan capital investment and the resulting increase in property tax expense due to that incremental investment accounts for $3,395,893 of the CY 2023 revenue requirement increase over the FY 2023-NG revenue requirement. There was an increase of $64,000 related to the total CY 2023 VM, I&M and Other Program O&M expense over the prior year. Lastly, the total CY 2023 revenue requirement was reduced for the tax hold harmless adjustment of $1,119,763.

Q. Please explain the increase of CY 2024 Electric ISR Plan revenue requirement over the CY 2023 proposed revenue requirement.

A. As mentioned above, the Company's CY 2024 Electric ISR Plan revenue requirement is $22,572,355 higher than the CY 2023 Electric ISR Plan revenue requirement. Of the total $67,073,688 CY 2024 revenue requirement, $37,723,589 in capital investment revenue requirement and $4,890,818 in property tax recovery adjustment are associated with incremental non-growth ISR Plan capital investment for FY 2018 through CY 2023. The increase in the CY 2024 revenue requirement compared to the proposed CY 2023 plan revenue requirement on that same investment totals $11,001,967 and is mainly caused by the impact of increase related to the half-year convention applied in the year of service in the CY 2023 plan and an increase in that CY 2024 is a 12-month revenue requirement compared to only a nine-month revenue requirement for CY 2023. As a result, the CY 2024 revenue requirement on vintage year CY 2023 incremental non-growth ISR capital investment increased by $3,305,511 from the CY 2023 revenue requirement on the same investment. The CY 2024 proposed incremental non-growth ISR capital investment and the resulting increase in property tax expense due to that incremental investment accounts for $8,714,189 of the CY 2024 revenue requirement over the CY 2023 revenue requirement. There was an increase of $3,239,000 related to the total CY 2024 VM, I&M and Other Program O&M expense over CY 2023. The CY 2024 revenue requirement increase was offset by a reduction to the CY 2024 revenue requirement for $382,800 for the tax hold harmless adjustment over the CY 2023 adjustment amount.

Q. What are the impacts of the sale of the Company to PPL Rhode Island on the 21-Month Electric ISR Plan revenue requirement calculations?

A. On May 25, 2022, PPL Rhode Island, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of Company from National Grid (the "Acquisition"). The Acquisition was treated as an asset acquisition for tax purposes under Internal Revenue Code (IRC) §338(h)(10) ("the §338 election"), which resulted in the recognition of all book and tax timing differences and the reversal of the related deferred tax assets and liabilities in FY 2023. In addition, the Company utilized all its available Net Operating Losses ("NOL") to offset taxable income generated from the sale, which resulted in the reversal of all NOL related deferred tax assets in FY 2023. The reversal of all deferred tax assets and liabilities, including NOL deferred tax assets, reduced net deferred tax liabilities which increased the ISR rate base in the vintage revenue requirement calculations by $13,605,872 for CY 2023 and $18,257,139 for CY 2024. Consequently, the increase in rate base ultimately increases the return on rate base recoverable through the ISR mechanism. The expected impact to the 21-month Electric ISR Plan revenue requirement would be an increase of approximately $1,119,763 in CY 2023 and $1,502,563 in CY 2024 as shown on Section 5, Attachment 1, Page 1, Line 19 and shown in detail on Section 5, Attachment 2. The expected increase to the FY 2023-NG Electric ISR revenue requirement will be reflected in the Company's FY 2023-NG Electric ISR reconciliation to be filed by August 1, 2023.

Q. How does the Company propose to address the above increases to the revenue requirements on the FY 2024 Electric ISR Plan revenue requirement as a result of the Acquisition?

A. As part of the transaction approval proceeding before the Division of Public Utilities and Carriers in Docket No. D-21-09, PPL committed to hold harmless Rhode Island customers from any changes to Accumulated Deferred Income Taxes ("ADIT") as a result of the Acquisition.[2] The Company is proposing to reduce the CY 2023 and CY 2024 revenue requirements by the calculated hold harmless amounts as shown on Section 5, Attachment 1, Page 1, Line 19. Because of the §338 election, PPL generated tax-deductible goodwill, which creates cash tax benefits to the Company. These cash tax benefits will be shared with the customer in the form of revenue credits to offset the increase in revenue requirements from the increase in rate base because of the elimination of deferred taxes from the Acquisition. Under National Grid ownership, the Company generally filed its federal income tax return in December for its most recently completed fiscal year, and that timing has required the Company in past ISR Plan dockets to file revised Electric ISR Plan revenue requirements reflecting the actual tax deductions or NOL generated or utilized as submitted in its tax return. The Company will revise the revenue requirement in this filing to reflect the actual tax repair deductibility percentages and NOL utilization on vintage FY 2022 ISR Plan capital investment per the Company's filed FY 2022 federal income tax return.

[2] *See* Report and Order, Docket No. D-21-09 at 257, commitment #16 (February 23, 2023).

Q. Please describe any changes to the presentation of the revenue requirements calculations because of the Acquisition.

A. Because of the §338 election, the sale resulted in the reversal of book and tax timing differences and the related deferred taxes. In addition, tax depreciation starts over on a new tax basis equal to net book value on the date of Acquisition. To reflect these impacts of the Acquisition, the calculations of the FY 2023 rate base and revenue requirement for the vintage plan years FY 2018 through FY 2023-NG were separated into three columns in Section 5, Attachment 1, Pages 2, 6, 12, 16, 21, and 25. The first FY 2023 column labeled as "NG, 4/1/22-5/24/22", reflects the 55 days of National Grid ownership. The second FY 2023 column labeled as "PPL, 5/25/22-12/31/22" reflects the period from acquisition date through December 31, 2022, which represents the first year under PPL's ownership where the deferred taxes under National Grid's ownership are reversed and the tax basis becomes equal to net book basis, causing the book and tax timing difference and tax depreciation to start over. Because PPL files a tax return on a calendar year basis, the third FY 2023 column labeled "PPL, 1/1/23-3/31/23, representing January 1 through March 31, 2023, fall under a new tax return year for PPL in which tax depreciation is calculated for the 2023 calendar year and prorated to the first three months of 2023 in the FY 2023 plan. Once the impacts of the sale are reflected in the FY 2023 plan year, the calculations can be rolled forward into future years (i.e., the 21-month plan) to compute the proper rate base and revenue requirement.

Q. As a result of the Acquisition, are there any changes to the Company's policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes that affect the revenue requirement or rate impacts presented in this filing?

A. There is no impact on this filing. The Company is continuing to capitalize to the same thresholds as when it was owned by National Grid, pending further review to determine whether to make any changes to the capitalization policy thresholds, which also depend on the systems cutover.

Q. Please describe the process that PPL is undertaking to review the policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes.

A. The capitalization policies primarily and directly impacting the Property Plant and Equipment (PPE) amount capitalized can be broken down into three main types:

1) Retirement unit, also known as property unit, listing: This identifies those items (such as poles) which are individually capitalized upon replacement. Below this level, items (such as attaching hardware) are expensed when individually replaced. This listing is integrated with the compatible units used by the work management systems as well as substation and gas equipment estimating processes. PPL will analyze the retirement unit listing as part of the process to implement a new work management system for Rhode Island Energy.

2) Software: National Grid's software capitalization threshold is $250,000, while PPL's software capitalization threshold is $50,000. PPL would propose to eventually move to a common threshold to make future software project management of integrated systems easier. At this time, as part of the effort to transition the Company from National Grid to PPL systems to exit the Transition Services Agreement ("TSA"), PPL is expensing all transitional software projects for Rhode Island Energy, so there is no current impact on Rhode Island Energy regarding the software capitalization threshold. The expense is being recorded so that there is not impact to Rhode Island Energy customers.
3) General property, such as small tools and equipment, excluding software: See accompanying table for threshold differences between PPL and National Grid regarding small tools and equipment. In general, National Grid's capitalization thresholds are higher than PPL's. National Grid typically uses $500 to $2,500 thresholds for gas and electric, respectively. PPL uses thresholds ranging from $200 to $500, depending on types of equipment. PPL would use existing National Grid processes for procurement of these items in CY 2023, until PPL's supply chain systems are implemented. Afterwards, PPL would propose utilizing common thresholds for acquisition of general property such as small tools and equipment, to make most efficient use of common supply chain processes. Note that these types of materials are most frequently acquired based upon replacement needs, thus it is

difficult to identify what is going to be incurred in advance and the future impact of decreasing the thresholds is unknown at this time.

	POLICY OR PROCESS	CURRENT (INTERIM) TREATMENT FOR RHODE ISLAND ENERGY	FUTURE TREATMENT FOR RHODE ISLAND ENERGY
1	Retirement Unit (RU) Catalog (replacement of retirement unit is capital)	The Company has an existing RU catalog under National Grid (NG)	During 2023, continue to use existing NG RU catalog. During the design phase of the work management system implementation, PPL will evaluate whether to continue using the existing catalog or have the Company utilize PPL's RU catalog.
2	Software projects (capital)	NG applies a $250K threshold	PPL utilizes a $50K threshold for capitalization and plans to apply that threshold to RIE.
3	Software as a Service (SAAS) – cloud implementation costs	Not significant	Per FERC guidance, implementation costs will continue to be capitalized consistent with ASC 350.
4	Pre-capitalized materials (meters and line transformers)	Capitalized at purchase	No change
5	General Property – office furniture and computer equipment	Capital thresholds of $2,500 for electric and $500 for gas.	Utilize PPL's current threshold of $200 for both gas and electric, which supports use of a consistent and centralized purchases process.
6	General Property – Stores, tools, lab, communication and general plant equipment	Capital threshold of $2,500 for electric and $500 for gas	Utilize PPL's threshold of $500 for both gas and electric, which supports use of a consistent and centralized purchasing process.
7	Standby Emergency Capital Spares	Assets placed in-service as backups directly related to assets served (no more spares than assets being backed up)	No change
8	Capital Clearing Overheads	Where possible, costs are directly charged to capital projects, but where impractical, costs directly related to capital process are allocated to capital projects	Based on our discussions with NG, the PPL process to be utilized for the Company is similar. The biggest change is that PPL applies capital clearing overhead to cost of removal, while NG does not.
9	A&G Overheads	A portion of A&G that is deemed directly related to capital is allocated to capital projects.	Based on our discussions with NG, the PPL process to be utilized for the Company is similar.
10	Leasehold Improvements	Capital Threshold – follows general plant thresholds	Will continue to follow general plant thresholds, based upon revised levels above.

Q. What is the timeline for implementing changes to the Company's policies regarding capitalizing expenditures for plant, property, and equipment used for regulatory reporting purposes that could impact this filing or future ISR plan-related filings?

A. The current target is end of CY 2023; however, that target date depends on cutover of numerous complex systems.

Q. Please explain how any changes to the capitalization policies will affect the Company's ISR plan-related reconciliation filings, revenue requirements, and rate impacts for future ISR plan filings.

A. As indicated above, the earliest the Company expects any changes to the capitalization policies is CY 2024. To the extent that any changes to thresholds occur during CY 2024 and impact the Electric ISR Plan capitalization amounts included in the CY 2024 revenue requirement, the differences would be captured during the CY 2024 Electric ISR Plan Reconciliation filing, which compares the actual ISR capitalized amounts to the forecasted ISR Plan capital. Assuming that the review and capitalization changes are known before the Company files its CY 2025 Electric ISR Plan, the revenue requirement in the CY 2025 Electric ISR Plan would reflect these changes.

IV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

PRE-FILED DIRECT TESTIMONY

OF

PETER R. BLAZUNAS

Table of Contents

I. Introduction and Qualifications

Q. Please state your full name and business address.

A. My name is Peter R. Blazunas and my business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

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

A. I am a Project Manager for Concentric Energy Advisors, Inc. (“Concentric”), a management consulting firm. I am testifying on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”).

Q. Please describe your educational background and training.

A. I received a Bachelor of Arts degree in Economics from the University of Dayton in 2009 and a Master of Arts degree in Economics from the University of Akron in 2011.

Q. Please describe your professional experience.

A I began my career with FirstEnergy Corp. in 2012 as a State Regulatory Analyst in the Ohio Rates and Regulatory Affairs Department. In July 2017, I joined the Potomac Electric Power Company (“Pepco”) Regulatory Strategy and Revenue Policy team of the Regulatory Affairs Department of Pepco Holdings Inc. (“PHI”) as a Senior Rate Analyst. In November 2018, I assumed the position of Manager of Rate Administration for Pepco. In that role, I was responsible for the development of electric rates, including tariff surcharges, for Pepco's Maryland and District of Columbia jurisdictions, and also participated in the development of Pepco's policies and practices with respect to rate design and assisted with regulatory compliance matters, including tariff administration and periodic filings. I left Pepco in January 2021 and assumed my current role at Concentric in October 2021.

Q. Have you previously testified before Rhode Island Public Utilities Commission ("PUC")?

A. Yes. I have submitted pre-filed testimony before the PUC in support of the Company's Renewable Energy ("RE") Growth Program Factor filing in Docket No. 22-04-REG, the Company's Gas Revenue Decoupling Mechanism ("RDM") Reconciliation filing in Docket No. 22-13-NG, the Company's Distribution Adjustment Charge ("DAC") in Docket No. 22-13-NG, the Company's Electric Infrastructure, Safety, and Reliability ("ISR") Plan Annual Reconciliation filing in Docket No. 5098, and the Company's Gas Cost Recovery ("GCR") Filing in Docket No. 22-20-NG.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the proposed factors designed to recover the fiscal year ("FY") 2024 revenue requirement on cumulative actual and forecasted incremental capital investment through December 31, 2024 and FY 2024 operation and maintenance ("O&M") expense resulting from the Company's FY

2024 Electric ISR Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

II. Infrastructure, Safety, and Reliability Provision

Q. Please describe the Company's ISR Plan tariff provision.

A. The Company's ISR Provision, R.I.P.U.C. No. 2199, describes the process for establishing and implementing annual rate adjustments designed to recover the costs associated with the electric ISR plan. The tariff consists of two separate mechanisms: (1) an Infrastructure Investment Mechanism ("IIM") designed to recover the costs associated with incremental capital investment; and (2) an Operation and Maintenance Mechanism ("O&MM") designed to recover certain annual O&M expense pertaining to Inspection and Maintenance ("I&M"), Vegetation Management ("VM") activities, and any other O&M expense as approved by the PUC.

A. Infrastructure Investment Mechanism

Q. Please describe the operation of the IIM.

A. The IIM provides for the recovery of incremental capital investment through CapEx Factors. In conjunction with the filing of the annual electric ISR plan by January 1 of each year, the Company proposes CapEx Factors for each rate class designed to recover the revenue requirement associated with forecasted and actual cumulative capital investment through the end of the upcoming ISR plan year. The proposed CapEx Factors become effective on and after April 1 of each ISR plan year upon PUC approval.[1]

Q. How are the CapEx Factors designed?

A. First, the revenue requirement approved by the PUC, which will reflect both an estimate of incremental capital investment for the upcoming ISR plan year plus the cumulative actual and forecasted incremental capital investment for prior ISR plan years including the current ISR plan year, is allocated to each of the Company's rate classes based upon the rate base allocator. The rate base allocator is the percentage of total rate base allocated to each rate class taken from the Company's most recent general rate case before the PUC that contained an allocated cost of service study.

Next, unit rates for each rate class are developed from the allocated revenue requirement. For non-demand rate classes, a per-kWh rate is calculated by dividing each rate class's share of the revenue requirement by its forecasted kWh deliveries for the period during which the rates will be in effect. For demand-based rate classes, Rate G-02 and Rates G-32/B-32, the CapEx Factors are per-kW rates and are calculated by dividing the allocated revenue requirement for each rate class by an estimate of the kW billing demand for the period the rates will be in effect.

[1] The Company's FY 2024 CapEx factors are proposed to be in effect April 1, 2023 through December 31, 2024.

Q. Please explain why the revenue requirement is allocated using a rate base allocator.

A. A rate base allocator is used to allocate the revenue requirement associated with cumulative incremental capital investment to the Company's rate classes as it is similar to the manner by which the revenue requirement on capital investment would be allocated in an allocated cost of service study. Since capital investment is primarily related to plant in service, which forms the largest part of rate base, allocating the incremental capital investment using the rate base allocator contained in the allocated cost of service study in the Company's most recent general rate case is an appropriate way to spread the revenue requirement to each of the rate classes.

Q. Is the revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors subject to reconciliation?

A. Yes. The Company submits its annual ISR Reconciliation Filing by August 1 of each year in which the Company compares the revenue requirement on actual cumulative incremental capital investment to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over- or under-recovery of the revenue requirement is credited to or recovered from customers through CapEx Reconciling Factors effective on the October 1 following the filing. The amount approved for recovery or crediting through CapEx Reconciling Factors is also subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors, and any difference reflected in future CapEx Reconciling Factors.

B. <u>Operation and Maintenance Mechanism</u>

Q. Please describe the operation of the O&MM.

A. The O&MM provides for the recovery of the proposed O&M expense presented in the ISR plan. The O&M Factor for each rate class is designed to recover the sum of the annual forecasted O&M expense for the upcoming ISR plan year, as approved by the PUC in the Company's annual electric ISR plan filing.

Q. How are the O&M Factors designed?

A. To determine each rate class's O&M Factor, the forecasted O&M expense is allocated to each of the Company's rate classes based upon the O&M allocator derived from allocated distribution O&M expense (i.e., FERC accounts 580-598). This distribution O&M allocator is the percentage of total distribution O&M expense allocated to each rate class taken from the most recent proceeding before the PUC that contained an allocated cost of service study.

Once the rate class O&M revenue requirement has been determined, per-unit rates are developed for each rate class. For Large Demand Back Up Service Rate B-32, the O&M Factor for Backup Service is in the form of a demand, or per-kW, rate and is calculated by dividing the allocated O&M expense for the combined Rate B-32/G-32 rate class by an estimate of the kW billing demand for the 21 month period the factor is to be in effect, truncating the result to 2 decimal places, then applying a 90% discount by multiplying the resulting charge by 0.1. For all other rate classes, a per-kWh rate is developed by dividing the allocated O&M expense by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect.[2]

Q. Why is the O&M expense allocated using a distribution O&M allocator?

A. As with the allocation of the revenue requirement on capital investment, the O&M expense is allocated in a manner that is similar to the way these costs would be allocated in an allocated cost of service study. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last general rate case is used to spread these costs to each of the Company's rate classes.

Q. Regarding Rates G-02 and B-32/G-32, why are the CapEx Factors designed as demand (per-kW) charges and the O&M Factors as per-kWh charges?

A. The current distribution rate structure for Rates G-02 and B-32/G-32 include both demand and kWh rates. The designs of the CapEx Factors and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing

[2] The Company's FY 2024 O&M factors are proposed to be in effect April 1, 2023 through December 31, 2024.

rates and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts.

Q. Are the O&M Factors subject to reconciliation?

A. Yes. In the Company's annual ISR Reconciliation Filing, the Company compares the actual O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over- or under-recovery of actual expense is credited to or recovered from customers through the O&M Reconciling Factor effective on the October 1 following the filing. The O&M Reconciling Factor is a uniform per-kWh rate applicable to all rate classes. The amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

III. Proposed Factors

A. CapEx Factors

Q. Please describe the calculation of the proposed CapEx Factors.

A. The CapEx Factors are designed on a FY 2024 ISR capital-related revenue requirement net of tax hold harmless adjustments of $81,930,022[3] as developed in the testimony of

[3] See Section 5: Attachment 1, Page 1, Line 17, Columns (b) and (c) plus Line 19, Columns (b) and (c).

Company Witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore, and Natalie Hawk. The revenue requirement is allocated to the rate classes based on the rate base allocator approved in Docket No. 4770, and the factors are designed as described above using forecasted billing units for the period April 1, 2023, through December 31, 2024. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

B. <u>O&M FACTORS</u>

Q. Please describe the calculation of the proposed O&M Factors.

A. The proposed O&M Factors are designed to recover forecasted O&M expense for FY 2024 of $29,645,000[4] as developed in the testimony of Company Witnesses Jeffrey D. Oliveira, Stephanie A. Briggs, Andrew W. Elmore, and Natalie Hawk. The Company has allocated this O&M expense using the distribution O&M allocator approved in Docket No. 4770. O&M Factors are designed as I describe above. The calculation of the proposed O&M Factors is set forth in the ISR Plan, Section 6, page 2.

Q. Is the Company providing a summary of all proposed factors?

A. Yes. The Summary of Proposed Factors is presented in Section 6, page 1.

[4] See Section 5: Attachment 1, Page 1, Line 4, Column (b) plus Column (c).

IV. Bill Impacts

Q. Has the Company prepared monthly bill impacts illustrating the effect of the proposed ISR factors?

A. Yes. The monthly bill impacts for each rate class are shown in Section 7 of the ISR Plan. For a residential customer receiving Last Resort Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.32, or 0.8%.

V. Summary of Retail Delivery Rates

Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, R.I.P.U.C. No. 2095, in this filing?

A. No, the Company is not revising this tariff at this time. The Company will submit its Annual Retail Rate Filing in February 2023 and will propose additional rate changes for effect April 1, 2023. Therefore, the Company will submit a compliance filing following the PUC’s decision in both the Annual Retail Rate Filing docket and this docket that will include the Summary of Retail Delivery rates tariff reflecting all of the approved rate changes for effect April 1, 2023.

VI. Docket 4600

Q. Did the Company apply the Docket 4600 principles of rate design to the FY 2024 Electric ISR Plan?

A. The Company did not perform a specific analysis of the rate design principles in the context of the proposed FY 2024 Electric ISR Plan. Rhode Island Gen. Laws § 39-1-27.7.1 provides for a spending plan for each fiscal year and an annual rate-reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget. The PUC has previously approved the rate design for the ISR recovery factors as part of the ISR Provision, R.I.P.U.C. No. 2199, effective September 1, 2018. The Company is not proposing any changes to the current rate design as part of the FY 2024 Electric ISR Plan.

VII. Tariff Modifications

Q. Is the Company proposing modifications to the Electric ISR Provision tariff, R.I.P.U.C. No. 2255, as a part of this filing?

A. Yes. Attachment PRB-1 provides a clean and redline version of the Company's Electric ISR Provision tariff.

Q. Please describe the nature of the changes the Company is proposing to the Electric ISR Provision tariff, R.I.P.U.C. No. 2255.

A. The Company's proposed changes to the Electric ISR Provision tariff effective April 1, 2023, reflect the fact that the Company is proposing a one-time twenty-one month plan for the period April 1, 2023, through December 31, 2024, as compared to the twelve-month plans covering the period April through March that it has proposed historically.

Furthermore, it is the Company's intent to move to twelve-month plans covering the period January through December beginning January 1, 2025. Consequently, the Electric ISR Provision tariff effective January 1, 2025, would need to be modified again to reflect this change.

Q. As a result of its one-time proposal for a twenty-one month plan, is the Company presently proposing any modifications to the Electric ISR Provision tariff language with respect to the CapEx Reconciling Factor and the O&M Reconciling Factor?

A. No, not at this time. The current language in the tariff properly accounts for the fact that the Company's next adjustments of the CapEx Reconciling Factor and the O&M Reconciling Factor will be filed August 1, 2023, with an effective date of October 1, 2023, through September 30, 2024, and will reconcile the fiscal year 2023 (April 2022 – March 2023) ISR plan presently in effect. As a part of its August 1, 2023, annual ISR Reconciliation Filing to adjust the CapEx Reconciling Factor and the O&M Reconciling Factor the Company will, however, include a proposal, including tariff language related to the timing of filing and effective dates, with respect to the reconciliation of the one-time FY 2024 twenty-one month plan and the twelve-month plans thereafter.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment PRB-1

Electric ISR Provision Tariff (RIPUC No. 2264) – Clean and Redline

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

In accordance with the provisions of *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for electric distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Electric Infrastructure, Safety, and Reliability ("ISR") Provision.

I. Infrastructure Investment Mechanism

A. Definitions

"Actual Capital Investment" shall mean the sum of i) "Discretionary Capital Investment" and ii) "Non-Discretionary Capital Investment", as defined below, plus cost of removal.

"CapEx Factor" shall mean the per-kWh factor for non-demand rate classes designed to recover the Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, based on Forecasted kWh for the Current Year for each non-demand rate class. For demand-based rate classes Rate G-02, and Rates G-32/B-32, the CapEx Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for each demand-based rate class.

"CapEx Reconciling Factor" shall mean the per-kWh factor designed to recover or refund the over or under billing of the actual Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

"Cumulative CapEx" shall mean the cumulative Actual Capital Investment for years prior to the Current Year plus Forecasted Capital Investment for the Current Year, recorded since the end of the Company's rate year in its most recent general rate case and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment for any period during which Forecasted Capital Investment has not been reconciled to Actual Capital Investment, including through the end of the Company's rate year in its most recent general rate case.

"Cumulative Revenue Requirement" shall mean the return and taxes on year-end cumulative Incremental Rate Base, at a rate equal to the pre-tax weighted average cost of capital as approved by the Commission in the most recent proceeding before the Commission, plus the annual depreciation on Cumulative CapEx as defined above, plus the annual municipal property taxes on Cumulative CapEx, as calculated in the illustration below.

"Current Year" shall mean the fiscal year beginning April 1 of the current year and running through ~~March~~ December 31 of the subsequent year during which the proposed CapEx Factor and O&M Factor will be in effect.

"Discretionary Capital Investment" shall mean capital investment, other than 'Non-Discretionary' Capital Investment defined below, approved by the Commission as part of the

Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Forecasted Capital Investment" shall mean the estimated capital investment and cost of removal anticipated to be incurred/recorded by the Company for a given fiscal year associated with electric distribution infrastructure consistent with its capital forecast.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the ~~twelve~~ twenty-one month period during which the proposed factors, as defined in this ISR Provision, will be in effect.

"Incremental Rate Base" shall mean the Cumulative CapEx adjusted for accumulated depreciation and calculated accumulated deferred taxes on Cumulative CapEx since the end of the Company's rate year in its most recent general rate case, and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment , including through the end of the Company's rate year in its most recent general rate case.

"Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Rate Base Allocator" shall mean the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

B. Recovery Mechanism

The CapEx Factors shall recover the Cumulative Revenue Requirement on Cumulative CapEx as approved by the Commission in the Company's annual Electric ISR Filings. The CapEx Factors shall be applicable for the ~~twelve~~ twenty-one month period commencing April 1.

The Company's electric ISR mechanism shall include an annual CapEx Factor reconciliation which will reconcile actual Cumulative Revenue Requirement to actual billed revenue generated from the CapEx Factors for the applicable Current Year. The recovery or refund of the reconciliation amounts (either positive or negative) shall be reflected in CapEx Reconciling Factors. The Company shall submit a filing by August 1 of each year ("Reconciliation Filing"), in which the Company shall propose the CapEx Reconciling Factors to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the CapEx Reconciling Factors shall be subject to reconciliation with amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

II. Operation and Maintenance Mechanism

A. Definitions

"Actual I&M Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with its I&M Program.

"Actual VM Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with vegetation management.

"Forecasted I&M Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with its I&M Program.

"Forecasted VM Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with vegetation management.

"I&M Program" shall mean the Company's Inspection and Maintenance Program and related inspection and maintenance activities.

"O&M" shall mean expenses of the Company recorded in FERC regulatory accounts 580 through 598 pursuant to FERC's Code of Federal Regulations.

"O&M Allocator" shall mean the percentage of total O&M allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

"O&M Factor" shall mean the per-kWh factor for all rate classes, except for Rate B-32, designed to recover the Forecasted I&M Expense and Forecasted VM Expense for the Current Year, as allocated by the O&M Allocator, based on Forecasted kWh for the Current Year for each rate class. For Rate B-32, the O&M Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for the rate class

"O&M Reconciling Factor" shall mean the uniform per-kWh factor designed to recover or refund the under or over billing of Actual I&M Expense and Actual VM Expense for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

B. Recovery Mechanism

The O&M Factor shall recover the sum of the annual Forecasted I&M Expense and Forecasted VM Expense as approved by the Commission in the Company's annual Electric ISR

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

Filings. The O&M Factor shall be applicable for the ~~twelve~~ twenty-one month period commencing April 1.

The Company's Electric ISR mechanism shall include an annual O&M Factor reconciliation which will reconcile Actual I&M Expense and Actual VM Expense to actual billed revenue from the O&M Factor for the Current Year. The recovery or refund of the reconciliation amount (either positive or negative) shall be reflected in the O&M Reconciling Factor. In its Reconciliation Filing, the Company shall propose the O&M Reconciling Factor to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the O&M Reconciling Factor shall be subject to reconciliation with amounts billed through the O&M Reconciling Factor and any difference reflected in a future O&M Reconciling Factor.

III. Annual Electric Infrastructure, Safety, and Maintenance Plan

By January 1 of each year, the Company shall submit to the Commission for review and approval its proposed Electric Infrastructure, Safety, and Reliability Plan ("Electric ISR Plan") for the upcoming Current Year. The Electric ISR Plan shall consist of Forecasted Capital Investment, Forecasted I&M Expense, Forecasted VM Expense, and, if mutually agreed upon by the Division and the Company, the revenue requirement, whether the result of capital investment or O&M expenditures, of any other cost relating to maintaining safe and reliable electric service.

IV. Annual Report on Electric ISR Plan Activities

The Company's August 1 Reconciliation Filing shall include an annual report on the prior fiscal year's activities. In implementing its Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plans approved by the Commission. In such cases, in the annual report, the Company would include an explanation of any deviations in excess of ten (10) percent above Forecasted Capital Investment, Forecasted I&M Expense, and Forecasted VM Expense. For cost recovery purposes, the Company has the burden to show that any such deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent.

V. Adjustments to Rates

Modifications to the factors contained in this Electric ISR Provision shall be in accordance with a notice filed with the Commission setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

The Narragansett Electric Company

Illustrative ISR Property Tax Recovery Calculation

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**RY End**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 1**
1	Plant In Service	$13,584,700	$55,000	$2,000	$57,000		($9,400)		$13,632,300
2									
3	Accumulated Depr	$611,570				$45,039	($9,400)	($7,200)	$640,009
4									
5	Net Plant	$12,973,130							$12,992,291
6									
7	Property Tax Expense	$29,743							$31,274
8									
9	Effective Prop tax Rate	0.23%							0.24%
10									
11									
12		**Yr 2 Beg**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 2**
13									
14	Plant In Service	$13,632,300	$60,000	$2,200	$62,200		($9,500)		$13,685,000
15									
16	Accumulated Depr	$640,009				$45,039	($9,500)	($7,400)	$668,148
17									
18	Net Plant	$12,992,291							$13,016,852
19									
20	Property Tax Expense	$31,274							$32,897
21									
22	Effective Prop tax Rate	0.24%							0.25%
23									
24									
25		**(a)**	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**
26	**Property Tax Recovery Calculation**								
27			**ISR YR 1**				**ISR YR 2**		
28									
29	ISR Additions		$55,000				$60,000		
30	Rate Year Book Depr		($45,039)				($45,039)		
31	COR - ISR YR		$7,200				$7,400		
32									
33	Net Plant Additions		$17,161				$22,361		
34									
35	RY Effective Tax Rate		0.23%				0.23%		
36	Year 1 ISR Property Tax Recovery			$39				$51	
37	Year 2 ISR Property Tax Recovery							$35	
38									
39	ISR Year Effective Tax Rate	0.24%				0.25%			
40	RY Effective Tax Rate	0.23%	0.01%			0.23%	0.02%		
41									
42	RY Net Plant	$12,973,130				$12,973,130			
43	ISR Yr 1 Net Adds	$17,161				$15,291			
44	ISR Yr 2 Net Adds		$12,990,291			$22,361	$13,010,782		
45				$1,487				$3,052	
46									
47	Total ISR Property Tax Recovery			$1,526				$3,139	
48									
49	Incremental ISR Property Tax Recovery			$1,526				$1,612	

Line Notes

1 Col (a) per Rate Year cost of service, Col (b), (cc), (d) and (f) per Actual ISR filing Col (e) equals Base Rate depreciation expense allowance
3 Col (a) per Rate Year cost of service, (e) equals Base Rate depreciation expense allowanceCol (h) Col (b), (cc), (d) and (f) per Actual ISR filing
7 Col (a) Base Rate property tax expense allowance
36 Line 33 times Line 35
37 Col (g) equals Line 43, Col (e) Times Rate Year effective Property Tax Rate Line 9 Col (a) - (15,291 X 3.97%)
43 Col (e) equals Line 33, Col (b) less ISR Yr 1 additions, Line 29, Col (b) times composite book depreciation rate of 3.4% - (17,161 - 55,000 X 3.4%)
45 Line 40 times Line 44

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

In accordance with the provisions of *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for electric distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Electric Infrastructure, Safety, and Reliability ("ISR") Provision.

I. <u>Infrastructure Investment Mechanism</u>

A. <u>Definitions</u>

"Actual Capital Investment" shall mean the sum of i) "Discretionary Capital Investment" and ii) "Non-Discretionary Capital Investment", as defined below, plus cost of removal.

"CapEx Factor" shall mean the per-kWh factor for non-demand rate classes designed to recover the Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, based on Forecasted kWh for the Current Year for each non-demand rate class. For demand-based rate classes Rate G-02, and Rates G-32/B-32, the CapEx Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for each demand-based rate class.

"CapEx Reconciling Factor" shall mean the per-kWh factor designed to recover or refund the over or under billing of the actual Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

"Cumulative CapEx" shall mean the cumulative Actual Capital Investment for years prior to the Current Year plus Forecasted Capital Investment for the Current Year, recorded since the end of the Company's rate year in its most recent general rate case and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment for any period during which Forecasted Capital Investment has not been reconciled to Actual Capital Investment, including through the end of the Company's rate year in its most recent general rate case.

"Cumulative Revenue Requirement" shall mean the return and taxes on year-end cumulative Incremental Rate Base, at a rate equal to the pre-tax weighted average cost of capital as approved by the Commission in the most recent proceeding before the Commission, plus the annual depreciation on Cumulative CapEx as defined above, plus the annual municipal property taxes on Cumulative CapEx, as calculated in the illustration below.

"Current Year" shall mean the fiscal year beginning April 1 of the current year and running through December 31 of the subsequent year during which the proposed CapEx Factor and O&M Factor will be in effect.

"Discretionary Capital Investment" shall mean capital investment, other than 'Non-Discretionary' Capital Investment defined below, approved by the Commission as part of the

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Forecasted Capital Investment" shall mean the estimated capital investment and cost of removal anticipated to be incurred/recorded by the Company for a given fiscal year associated with electric distribution infrastructure consistent with its capital forecast.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twenty-one month period during which the proposed factors, as defined in this ISR Provision, will be in effect.

"Incremental Rate Base" shall mean the Cumulative CapEx adjusted for accumulated depreciation and calculated accumulated deferred taxes on Cumulative CapEx since the end of the Company's rate year in its most recent general rate case, and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment , including through the end of the Company's rate year in its most recent general rate case.

"Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Rate Base Allocator" shall mean the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

B. <u>Recovery Mechanism</u>

The CapEx Factors shall recover the Cumulative Revenue Requirement on Cumulative CapEx as approved by the Commission in the Company's annual Electric ISR Filings. The CapEx Factors shall be applicable for the twenty-one month period commencing April 1.

The Company's electric ISR mechanism shall include an annual CapEx Factor reconciliation which will reconcile actual Cumulative Revenue Requirement to actual billed revenue generated from the CapEx Factors for the applicable Current Year. The recovery or refund of the reconciliation amounts (either positive or negative) shall be reflected in CapEx Reconciling Factors. The Company shall submit a filing by August 1 of each year ("Reconciliation Filing"), in which the Company shall propose the CapEx Reconciling Factors to become effective for the twelve months beginning October 1. The amount approved for

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

recovery or refund through the CapEx Reconciling Factors shall be subject to reconciliation with amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

II. Operation and Maintenance Mechanism

A. Definitions

"Actual I&M Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with its I&M Program.

"Actual VM Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with vegetation management.

"Forecasted I&M Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with its I&M Program.

"Forecasted VM Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with vegetation management.

"I&M Program" shall mean the Company's Inspection and Maintenance Program and related inspection and maintenance activities.

"O&M" shall mean expenses of the Company recorded in FERC regulatory accounts 580 through 598 pursuant to FERC's Code of Federal Regulations.

"O&M Allocator" shall mean the percentage of total O&M allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

"O&M Factor" shall mean the per-kWh factor for all rate classes, except for Rate B-32, designed to recover the Forecasted I&M Expense and Forecasted VM Expense for the Current Year, as allocated by the O&M Allocator, based on Forecasted kWh for the Current Year for each rate class. For Rate B-32, the O&M Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for the rate class

"O&M Reconciling Factor" shall mean the uniform per-kWh factor designed to recover or refund the under or over billing of Actual I&M Expense and Actual VM Expense for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

B. Recovery Mechanism

The O&M Factor shall recover the sum of the annual Forecasted I&M Expense and Forecasted VM Expense as approved by the Commission in the Company's annual Electric ISR

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

Filings. The O&M Factor shall be applicable for the twenty-one month period commencing April 1.

The Company's Electric ISR mechanism shall include an annual O&M Factor reconciliation which will reconcile Actual I&M Expense and Actual VM Expense to actual billed revenue from the O&M Factor for the Current Year. The recovery or refund of the reconciliation amount (either positive or negative) shall be reflected in the O&M Reconciling Factor. In its Reconciliation Filing, the Company shall propose the O&M Reconciling Factor to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the O&M Reconciling Factor shall be subject to reconciliation with amounts billed through the O&M Reconciling Factor and any difference reflected in a future O&M Reconciling Factor.

III. Annual Electric Infrastructure, Safety, and Maintenance Plan

By January 1 of each year, the Company shall submit to the Commission for review and approval its proposed Electric Infrastructure, Safety, and Reliability Plan ("Electric ISR Plan") for the upcoming Current Year. The Electric ISR Plan shall consist of Forecasted Capital Investment, Forecasted I&M Expense, Forecasted VM Expense, and, if mutually agreed upon by the Division and the Company, the revenue requirement, whether the result of capital investment or O&M expenditures, of any other cost relating to maintaining safe and reliable electric service.

IV. Annual Report on Electric ISR Plan Activities

The Company's August 1 Reconciliation Filing shall include an annual report on the prior fiscal year's activities. In implementing its Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plans approved by the Commission. In such cases, in the annual report, the Company would include an explanation of any deviations in excess of ten (10) percent above Forecasted Capital Investment, Forecasted I&M Expense, and Forecasted VM Expense. For cost recovery purposes, the Company has the burden to show that any such deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent.

V. Adjustments to Rates

Modifications to the factors contained in this Electric ISR Provision shall be in accordance with a notice filed with the Commission setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

The Narragansett Electric Company

Illustrative ISR Property Tax Recovery Calculation

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**RY End**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 1**
1	Plant In Service	$13,584,700	$55,000	$2,000	$57,000		($9,400)		$13,632,300
2									
3	Accumulated Depr	$611,570				$45,039	($9,400)	($7,200)	$640,009
4									
5	Net Plant	$12,973,130							$12,992,291
6									
7	Property Tax Expense	$29,743							$31,274
8									
9	Effective Prop tax Rate	0.23%							0.24%
10									
11									
12		**Yr 2 Beg**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 2**
13									
14	Plant In Service	$13,632,300	$60,000	$2,200	$62,200		($9,500)		$13,685,000
15									
16	Accumulated Depr	$640,009				$45,039	($9,500)	($7,400)	$668,148
17									
18	Net Plant	$12,992,291							$13,016,852
19									
20	Property Tax Expense	$31,274							$32,897
21									
22	Effective Prop tax Rate	0.24%							0.25%
23									
24									
25		**(a)**	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**
26	**Property Tax Recovery Calculation**								
27			**ISR YR 1**				**ISR YR 2**		
28									
29	ISR Additions		$55,000				$60,000		
30	Rate Year Book Depr		($45,039)				($45,039)		
31	COR - ISR YR		$7,200				$7,400		
32									
33	Net Plant Additions		$17,161				$22,361		
34									
35	RY Effective Tax Rate		0.23%				0.23%		
36	Year 1 ISR Property Tax Recovery			$39				$51	
37	Year 2 ISR Property Tax Recovery							$35	
38									
39	ISR Year Effective Tax Rate	0.24%				0.25%			
40	RY Effective Tax Rate	0.23%	0.01%			0.23%	0.02%		
41									
42	RY Net Plant	$12,973,130				$12,973,130			
43	ISR Yr 1 Net Adds	$17,161				$15,291			
44	ISR Yr 2 Net Adds		$12,990,291			$22,361	$13,010,782		
45				$1,487				$3,052	
46									
47	Total ISR Property Tax Recovery			$1,526				$3,139	
48									
49	Incremental ISR Property Tax Recovery			$1,526				$1,612	

Line Notes

1 Col (a) per Rate Year cost of service, Col (b), (cc), (d) and (f) per Actual ISR filing Col (e) equals Base Rate depreciation expense allowance
3 Col (a) per Rate Year cost of service, (e) equals Base Rate depreciation expense allowanceCol (h) Col (b), (cc), (d) and (f) per Actual ISR filing
7 Col (a) Base Rate property tax expense allowance
36 Line 33 times Line 35
37 Col (g) equals Line 43, Col (e) Times Rate Year effective Property Tax Rate Line 9 Col (a) - (15,291 X 3.97%)
43 Col (e) equals Line 33, Col (b) less ISR Yr 1 additions, Line 29, Col (b) times composite book depreciation rate of 3.4% - (17,161 - 55,000 X 3.4%)
45 Line 40 times Line 44