Rhode Island Energy

The Narragansett Electric Company

FY 2024 Electric Infrastructure, Safety and Reliability Plan

Annual Reconciliation

August 1, 2024

Docket No. 22-53-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

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Rhode Island Energy™
a PPL company

August 1, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-53-EL - FY 2024 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please see the Company's Annual Reconciliation for the Fiscal Year ("FY") 2024[1] Electric Infrastructure, Safety, and Reliability ("ISR") Plan (this "Filing" or "Reconciliation Filing"). This Filing is being submitted to the Public Utilities Commission ("PUC") in accordance with R.I. Gen. Laws § 39-1-27.7.1(c) and Sections (I)(B) and (IV) of the Infrastructure, Safety, And Reliability Provision, R.I.P.U.C. No. 2255 (the "ISR Provision").

This Filing consists of the following documents:

- **Pre-Filed Direct Testimony of Nicole A. Gooding** – The testimony of Ms. Gooding presents the Filing in relation to the FY 2024 Electric ISR Plan which was approved by the PUC in this docket. Attachment NAG-1, which is attached to Ms. Gooding's testimony, includes an Executive Summary, FY 2024 Plant in Service Additions, FY 2024 Capital Spending Summary, FY 2024 Capital Spending by Key Driver Category, FY 2024 Vegetation Management ("VM"), FY 2024 Other Operations and Maintenance ("O&M"), and Reliability Performance. See below for summary:

Item	Target/Budget	Actual
Plant in Service Additions	$89.0M	$97.3M
Cost of Removal Spending	$15.7M	$9.3M
Capital Spending	$112.3M	$124.7M
O&M Spending	$15.1M	$14.9M

[1] FY 2024 was April 1, 2023 through March 31, 2024.

In addition, Attachment NAG-1 includes the results of a review of distributed generation ("DG") projects undertaken by the Company. See below for summary of the results:

Item	Amount
Plant in Service between FY 2013 and FY 2022 as initially in rate base prior to the Company's review.	$11.8M
Plant in Service removed through the FY 2023 Reconciliation Filing while the Company conducted its review.	$10.6M (out of $11.8M)
Remaining Plant in Service between FY 2013 and FY 2022	$1.2M
Additional Plant in Service consisting of plant placed back into service from the $10.6M as well as new plant for FY 2024	$1.0M
Total Plant in Service FY 2013 through FY 2024	$2.2M

- **Pre-Filed Direct Testimony of Jeffrey D. Oliveira** – The testimony of Mr. Oliveira describes the calculation of the revenue requirement. The revenue requirement (including tax related adjustments as described in Ms. Hawk's testimony) totals $54,282,082. This is a decrease of $1,135,976 from the projected FY 2024 Electric ISR revenue requirement of $55,418,057, previously approved by the PUC in this docket.

- **Pre-Filed Direct Testimony of Natalie Hawk** – The testimony of Ms. Hawk describes tax related adjustments to the revenue requirement including the income tax components of the FY 2024 revenue requirement, FY 2024 tax updates used to calculate accumulated deferred income taxes ("ADIT"), FY 2023 tax updates which resulted in a "true-up" to the revenue requirement, and the hold harmless adjustments.

- **Pre-Filed Direct Testimony of Tyler G. Shields** – The testimony of Mr. Shields presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the ISR Provision, resulting from the reconciliation of actual costs and revenue associated with the FY 2024 ISR Plan. The impact of the proposed CapEx Reconciling Factor of $0.00020 per kWh and the proposed O&M Reconciling Factor of $0.00010 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is an increase of $0.86, or approximately 0.6%, from $137.54 to $138.40.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 22-53-EL Service List

Certificate of Service

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

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

Joanne M. Scanlon — August 1, 2024
Date

Docket No. 22-53-EL – RI Energy's Electric ISR Plan FY 2024
Service List as of 9/13/2023

Name/Address	E-mail Distribution	Phone
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PRE-FILED DIRECT TESTIMONY

OF

NICOLE A. GOODING

August 1, 2024

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I. Introduction and Qualifications

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

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

Q. Ms. Gooding, 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. Ms. Gooding, 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)?

A. Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2024 Electric Infrastructure, Safety and Reliability Plan in Docket 22-53-EL, the FY 2023 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation in Docket 5209, and the Tiverton and Weaver Hill Petitions for Acceleration Due to DG Project in Dockets 23-37-EL and 23-38-EL, respectively.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's FY 2024 Annual Reconciliation filing related to the Electric ISR Plan approved by the PUC in this docket. This filing provides the actual plant in service for discretionary and non-discretionary capital investment and associated cost of removal ("COR"), the actual vegetation management ("VM") operation and maintenance ("O&M") expenses, and the actual inspection and maintenance ("I&M") program and other O&M expenses for the period April 1, 2023, to March 31, 2024. As described in Mr. Jeffrey Oliveira's testimony in this filing, the plant in service investment and the O&M expenses are used to calculate the FY 2024 Electric ISR Plan revenue requirement. As explained in Mr. Tyler Shields' testimony in this filing, the annual capital investment revenue requirement on the actual cumulative ISR capital investment and the actual O&M expense incurred is then reconciled against the actual revenue billed during FY 2024. Specific details by category for the FY 2024 Electric ISR Plan plant additions, associated COR, and actual capital spending are included in Attachment NAG-1, which is attached to this testimony.

III. Plant In Service and Cost of Removal

Q. Please provide an overview of the plant in service and cost of removal for FY 2024.

A. As shown in Table 2 of Attachment NAG-1, in FY 2024, plant additions of $97.3 million were placed in service. This amount was $8.3 million over the target of $89.0 million. Non-Discretionary plant additions totaling $45.5 million were placed in service, which was $1.4 million over the target of $44.0 million. Actual plant additions related to transformer purchases were significantly higher than target. Discretionary plant additions totaling $51.8 million were placed in service, which was $6.9 million over the planned amount of $45.0 million. Assets associated with the Dyer Street Substation distribution line project went into service in FY 2024. These assets were expected to go into service in FY 2023, therefore, no additions were targeted in FY 2024.

As shown in Table 3 of Attachment NAG-1, the associated cost of removal was $9.3 million, which was $6.4 million lower than the FY 2024 target of $15.7 million. The primary drivers of the lower removal costs were the deferral of removal work at the Pawtucket #1 Substation, part of the Southeast Substation project, and Admiral Street Substation, part of the Providence Study Phase 1B project. These totals resulted in an Electric ISR Plan investment of $106.6 million, which was $1.9 million over the Company's target of $104.7 million. Additional details on these variances are included in Section I of Attachment NAG-1.

IV. Capital Spending

Q. Please summarize the Company's actual capital spending for FY 2024 for the Electric ISR Plan.

A. As shown in Table 4 of Attachment NAG-1, capital spending was $124.7 million. This amount was $12.4 million over the annual approved budget of $112.3 million.

Non-discretionary capital spending was $56.1 million, which was $13.4 million over the annual approved budget of $42.7 million.

For FY 2024, capital spending in the Discretionary sub-category (excluding large projects) was $37.6 million, which was $4.3 million under the annual approved budget of $41.9 million.

In FY 2024, the Southeast Substation, Dyer Street Substation, Providence Study, East Providence Substation, and Warren Substation projects were reported on separately from other Asset Condition and System Capacity & Performance projects. Capital spending was $31.0 million, which was $3.3 million over the annual approved budget of $27.7 million.

The key drivers and variances by category are discussed in detail in <u>Section III</u> of Attachment NAG-1.

Q. Is the Budgetary Framework, approved as part of the FY 2025 ISR Filing in Docket No. 23-48-EL, applicable to this FY 2024 ISR reconciliation?

A. No. It is the Company's understanding that FY 2025 will be the first ISR year subject to the newly approved Budgetary Framework. The Company did not manage the FY 2024 budget with the framework that was approved as part of the FY 2025 ISR Filing. The Company worked to manage within its discretionary budget. For example, the Company did not complete the budgeted amount of underground cable work because the same resources were needed to work on the Dyer Street Substation distribution line project. While the Company made shifts like this throughout the year within the discretionary portfolio, the Company did not decelerate discretionary work with the intention of offsetting overruns in non-discretionary spending.

Q. Please provide an update related to the Dyer Street Substation project and treatment of pre-construction costs.

A. In FY 2023, assets associated with the substation portion of the project were placed into service. In FY 2024, assets associated with the distribution line portion of the project were placed into service. Demolition of the existing Dyer Street Substation will begin once final permits are received. During FY 2023, the Company wrote off $0.9 million of the Dyer Street Substation project costs related to the preconstruction costs for the DC building. Once the entire project is complete, the Company will again review all costs to ensure spending related to the refurbishment of the DC building is not included in ISR rate base and revenue requirements.

Q. Please summarize the activity during the first year of the Company's CEMI program.

A. The Company identified the following feeders for the FY 2024 CEMI program: 112W44, 127W40, 34F1, 54F1, 63F6, 68F1, and 155F8. Work on these feeders was completed within the budget of $1.2 million. Detailed information regarding the work completed is in Attachment NAG-1, <u>Section VIII</u>, Customers Experiencing Multiple Interruptions (CEMI) Reporting. Performance should be evaluated after a suitable number of years, typically five or more. However, the Company will begin monitoring and reporting on specific feeder performance after three years to provide early insight into the CEMI program.

Q. Please summarize the Nasonville Damage/Failure work and its relationship to the discretionary project.

A. The scope of work associated with the August 2022 metal clad switchgear damage at Nasonville Substation is included in non-discretionary spending. The failed switchgear will be replaced with an open-air straight bus #1 that will include a main breaker, capacitor breaker, and three feeder breakers.

The Nasonville Substation discretionary project includes the expansion of the substation with a new four breaker bus as recommended in the Northwest Rhode Island Area Study. The substation expansion will be open-air design, with a new transformer due to be delivered in December 2024.

Q. Please provide the status of the Westerly #2 spare transformer.

A. The spare transformer was received in June 2024. It was set on a concrete foundation at the Kent County Substation, tested, and is available for use.

Q. Please explain the spending associated with Transformers.

A. During FY 2024, the Company spent $10.9 million on the purchase of transformers, capacitors, and voltage regulators. Over the last five years, half of the Company's overhead transformer purchases have seen price increases ranging from 17% to 240%.

Q. Please provide an explanation for the Non-Infrastructure capital spending credit balance of $(1.1) million.

A. The credit balance in the Non-Infrastructure spending rationale was driven by undistributed FY 2023 capital overheads in FY 2024. Capital overheads represent the indirect costs incurred to construct capital assets that cannot reasonably be attributed to a single asset. On a monthly basis, these costs are distributed using an overhead rate to capital projects monthly. In FY 2023, capital overheads were not fully distributed. In FY 2024, the FY 2023 undistributed capital overheads and the FY 2024 capital overheads were fully distributed to capital projects.

Q. Please provide an update on supply chain issues.

A. The Company still continues to experience supply chain constraints and increased lead times. The Company is taking these delivery schedules into consideration and ordering these materials earlier in the process than previously done to work to ensure that our need dates are met.

Q. Please provide an update on the Petitions for Acceleration Due to DG Project under Dockets 23-37 EL and 23-38 EL.

A. Briefs are currently pending in these dockets, scheduled to be filed during August 2024. No capital spending, removal or plant additions related to the Accelerated System

Modifications or System Improvements subject to either Docket No. 23-37-EL or Docket No. 23-38-EL have been included in this reconciliation filing.

Q. Did the Company include any Advanced Metering Functionality ("AMF") costs in the FY 2024 Annual Reconciliation?

A. Yes, the Company included $1.4 million of capital spending related to AMF in this filing. No assets were placed in service during the year and there are no rate impacts associated with AMF in-service to date.

V. <u>O&M Spending</u>

Q. Please summarize the Company's actual O&M spending for the FY 2024 Electric ISR Plan.

A. Total O&M spending was $14.9 million as compared to a budget of $15.1 million. As shown in <u>Table 11</u> of Attachment NAG-1, for FY 2024, the Company's vegetation management O&M spending was $13.8 million, which was under-budget by $0.2 million.

In addition, as shown in <u>Table 12</u>, the Company's Other O&M spending related to the I&M program and Volt/VAR Optimization and Conservations Voltage Reduction ("VVO/CVR") programs was $1.1 million, which was essentially on the approved

O&M budget of $1.2 million. Detailed information regarding the work completed is discussed in Attachment NAG-1 in Section IV and Section V, respectively.

VI. Reliability Performance

Q. Please summarize the results of the Company's reliability performance for CY 2023.

A. Section VI of Attachment NAG-1 includes the Company's Reliability Performance for calendar year 2023 (CY 2023). The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2023, with SAIFI of 0.769 against a target of 1.05, and SAIDI of 52.62 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[1]

VII. Review of Distributed Generation ("DG") Projects

Q. Please provide an update on the Company's review of DG projects.

A. As stated in the March 9, 2022, hearing, the Company undertook a review of DG projects including the allocation of capital contributions to projects by cost type, the identification of cost variance drivers, and the processes that support these items. The Company has completed this review and is implementing process changes based on the findings.

[1] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (6.27 minutes for CY 2023). 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.

In total, the Company reviewed $13.7 million in plant additions from FY 2013 through FY 2024 and determined that $2.2 million will remain in rate base. Customers were credited for the amount previously included in rate base in the FY 2023 Annual Reconciliation Filing. Please see Section IX of Attachment NAG-1 for more information.

Q. Please explain why the Company undertook this review.

A. During the discovery process in Docket No. 5209 (which reviewed the Company's FY 2023 ISR Plan), the Company was asked by the PUC to provide a schedule demonstrating how costs associated with a DG project are included in rate base, using the Company's Final Accounting methodology submitted in a separate docket, Docket No. 5206 (See Docket No. 5209, Company responses to PUC 2-7 and PUC-2-7 Supplemental). After reviewing the results of the PUC's question, the Company's witness, in her role as a sponsor of the FY 2023 ISR, determined that a review of the Company's historical accounting of costs in rate base associated with DG projects was warranted. The Company's witness determined that such a review was warranted based on what appeared to be anomalous data on the Company's books associated with DG customer contributions by cost type (e.g., capital, cost of removal and operating and maintenance expenses) and how such customer contributions were accounted for. In PUC 2-7 Supplemental, the actuals for the substation section were less than the estimate in total; however, the way the CIAC was allocated, there showed a debit in both removal and expense costs and a credit in capital and income tax. This example caused the Company to question if the CIAC was correctly allocated and undertake this review of DG projects.

Q. Why does the Company include any costs associated with DG interconnections in rate base?

A. Per the terms of the Company's interconnection tariff, DG customers are responsible for paying for the costs of system modifications on the Company's system necessary to interconnect their projects. The Company includes an estimate of such system modification costs in the DG customer's impact study results and the interconnection service agreement ("ISA"). Such costs are typically initial design costs with a probability of accuracy of plus or minus 25 percent. Such estimated costs are subject to further refinement by the Company after the customer executes an ISA and the Company performs more detailed design work associated with the customer's DG project. Per the Company's interconnection tariff, the DG customer is responsible for paying those estimated costs, but only up to 10 percent of such estimated costs. Although I am not a lawyer, my understanding is that, ultimately, to the extent that the Company incurs costs associated with interconnecting a DG project that are not recovered from the DG customer, the Company is allowed by Rhode Island law to recover the difference between its actual costs associated with the interconnection and the amount of costs paid by the DG customer for that interconnection, as long as the original estimate for the system modifications necessary to interconnect the DG customer's project were provided in good faith and interconnection was implemented prudently by the Company.

Q. Please explain what the Company reviewed.

A. The Company reviewed DG project cost reconciliations by cost type and how project contributions by DG customers were classified and accounted for from FY 2013 through FY 2024, when the first plant additions for DG projects were included in the ISR.

Q. What types of costs associated with DG interconnections were included in ISR rate base during the FY 2013- FY 2024 period?

A. Plant additions and cost of removal were included in ISR rate base.

Q. What process did the Company follow to review whether the Company had properly included such costs in rate base during this period?

A. Please see the Review Process outlined in <u>Section IX</u> of Attachment NAG-1.

Q. What was the total amount of plant additions associated with DG interconnections included by the Company in rate base during the FY 2013 - FY 2024 period?

A. As noted above and in <u>Section IX</u> of Attachment NAG-1, the Company included approximately $11.8 million in plant additions in rate base from FY 2013 through FY

2022. In FY 2023 and FY 2024, the Company has had $1.9 million of plant additions, but these were not included in rate base due to the ongoing review.

Q. Based on the Company's review, how much of these costs were removed from rate base for this FY 2024 ISR reconciliation filing?

A. The Company removed $10.6 million from FY 2018 through FY 2022 rate base associated with the Company's review during the FY 2023 Annual Reconciliation Filing, leaving $1.2 million in rate base as of March 31, 2023. The Company added approximately $1.0 million to rate base associated with the continued review in the past year, resulting in approximately $2.2 million in rate base for purposes of calculating the Company's ISR revenue requirement in the FY 2024 Annual Reconciliation.

Q. What were the reasons why the Company determined $10.6 million previously included in rate base should be removed?

A. In the first review which was completed before the FY 2023 Annual Reconciliation Filing, the Company found that costs should be removed from rate base due to: (1) refunds being issued to DG customers after final reconciliation of project costs; and (2) incorrect allocation of customer contributions to capital, expense and removal. Because of the amount that fell into these two categories in the first round of the review, the Company removed plant additions for those projects and the remaining that were not part of the first review set, totaling $10.6 million. When the Company completed the full review, the Company found that while the costs projects may have not fallen into (1) or (2) listed above, there was not enough information to justify them being put back into rate base. The Company determined that $1.2 million in costs should remain in rate base associated with: (1) costs that were incurred by the Company that were higher than the Company's good faith estimate of costs but could not be collected from the DG customer; or (2) system improvements that were completed by the Company as part of the scope of work associated with a DG project.

Q. Is the Company adjusting its proposed 2024 ISR factor to reflect the FY 2023 and FY 2024 rate base adjustments described above?

A. The Company reduced the revenue requirement in the FY 2023 Annual Reconciliation revenue requirement for the removal of the $10.6 million from rate base. Customers were credited, or made whole, from the amounts previously included in rate base and revenue requirement for FY 2018 through FY 2023. As discussed in the testimony of Mr. Oliveira, the FY 2024 Annual Reconciliation revenue requirement reflects the reductions made in the FY 2023 reconciled revenue requirement as well as an adjustment to the FY 2024 revenue requirement for the conclusions made in the past year.

Q. Is the Company implementing process changes to minimize the changes of these accounting anomalies from occurring in the future?

A. Yes. Please see the process improvements listed in <u>Section IX</u> of Attachment NAG-1.

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan
Annual Reconciliation Filing

EXECUTIVE SUMMARY

In accordance with its tariff, RIPUC No. 2199, Sheets 1-5, The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") submits this Annual Reconciliation Filing for the period April 1, 2023, through March 31, 2024 ("ISR Plan Fiscal Year 2024" or "FY 2024") for the Electric Infrastructure, Safety, and Reliability Plan approved by the Rhode Island Public Utilities Commission ("PUC") in Docket No. 22-53-EL. This filing provides the actual capital spending and operation and maintenance ("O&M") spending for the ISR Plan Fiscal Year 2024. In addition, actual Plant in Service and Cost of Removal spending are compared to targets for discretionary and non-discretionary categories. Finally, this filing includes a summary of the Company's reliability performance for the calendar year ("CY") ending December 31, 2023. Table 1 summarizes the FY 2024 Plan.

Table 1
FY 2024 ISR Plan Activity

		(a)	(b)	(c)
	in millions $	**Target / Budget**	**Actuals**	**Variance Over / (Under)**
1	Plant in Service Additions - Non-discretionary	$44.0	$45.5	$1.4
2	Plant in Service Additions - Discretionary	45.0	51.8	6.9
3	**Plant in Service Additions**	**$89.0**	**$97.3**	**$8.3**
4	Cost of Removal Spending - Non-discretionary	$4.4	$4.7	$0.3
5	Cost of Removal Spending - Discretionary	11.2	4.5	(6.7)
6	**Cost of Removal Spending**	**$15.7**	**$9.3**	**($6.4)**
7	Capital Spending - Non-discretionary	$42.7	$56.1	$13.4
8	Capital Spending - Discretionary	69.6	68.6	(1.0)
9	**Capital Spending**	**$112.3**	**$124.7**	**$12.4**
10	Vegetation Management Spending	$14.0	$13.8	($0.2)
11	I&M and Other O&M Spending	1.2	1.1	(0.0)
12	**O&M Spending**	**$15.1**	**$14.9**	**($0.2)**

This filing includes testimony from Mr. Oliveira, Ms. Hawk and Mr. Shields. Mr. Oliveira's testimony describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and O&M expenses for the year. His testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. Ms. Hawk's testimony describes an upward adjustment totaling $1,609,761 that was made for the tax hold harmless impact on ISR rate base.[1] As shown in Mr. Oliveira's testimony, for the ISR Plan Fiscal Year 2024 filing, the Company has an updated revenue requirement of $53.4 million.

Mr. Shields' testimony provides a description of the reconciliation of the final actual FY 2024 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Last Resort Service and using 500 kWhs per month is an increase of $0.86, or approximately 0.6 % from $137.54 to $138.40.

I. ISR Plan Fiscal Year 2024 Plant in Service Additions

As shown in Table 2 below, plant additions of $97.3 million were placed in service, $8.3 million over the target amount of $89.0 million. Non-discretionary plant additions of $45.5 million were placed in service, $1.4 million over the target of $44.0 million. Actual plant additions related to transformer purchases were significantly higher than target. Discretionary plant additions of $51.8 million were placed in service, $6.9 million over the planned amount of $45.0 million. Assets associated with the Dyer Street Substation distribution line project went into service in FY 2024. These assets were expected to go into service in FY 2023, therefore, no additions were targeted in FY 2024.

[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 (the "Acquisition"). 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.

Table 2
Plant Additions by Category

		(a) Target	(b) Actuals	(c) Variance Over / (Under)
1	Customer Request/Public Requirement	$27,742,000	$33,285,160	$5,543,160
2	Damage Failure	16,303,000	12,201,839	(4,101,161)
3	*Non-Discretionary subtotal*	*44,045,000*	*45,486,999*	*1,441,999*
4	Asset Condition	32,720,000	38,805,567	6,085,567
5	Non-Infrastructure	1,213,000	83,704	(1,129,296)
6	System Capacity & Performance	11,048,000	12,947,538	1,899,538
7	*Discretionary subtotal*	*44,981,000*	*51,836,809*	*6,855,809*
8	**Total Plant Additions**	**$89,026,000**	**$97,323,808**	**$8,297,808**

The variances shown in Table 2 reflect the timing of when plant is placed into service. In general, once equipment is energized and placed into service to support electric load, capital costs are transferred from FERC Account 107 (Construction Work in Progress or CWIP) to FERC Account 106 (Plant in Service), which is when capital work becomes used and useful in the service of customers. This can differ by the type of plant and facility. For example, electric distribution line equipment normally is placed in service closer to the time it is installed because it is typically energized at that time and begins to support electric load, and therefore, is used and useful in the service of customers. Because electric distribution line equipment is typically energized as it is installed, a relatively significant amount of plant is placed into service as work progresses. In contrast, substation construction typically involves multi-year projects. Because substation construction typically is completed in one or more phases as part of a multi-year process, the assets will be placed in service once all work in a phase is completed.

Table 3 provides the Cost of Removal for 2024, which was $9.3 million, $6.4 million under the forecast of $15.7 million. Non-discretionary Cost of Removal was $4.7 million, which was $0.3 million over the budgeted amount of $4.4 million. Discretionary Cost of Removal totaled $4.6 million, which was $6.7 million under the budgeted amount of $11.2 million, primarily caused by the deferral of removal work at the Pawtucket 1 Substation, part of the Southeast Substation project, and Admiral Street Substation, part of the Providence Study Phase 1B project.

Table 3
Cost of Removal by Category

		(a) Budget	(b) Actuals	(c) Variance Over / (Under)
1	Customer Request/Public Requirement	$2,314,000	$2,574,326	$260,326
2	Damage Failure	2,116,580	2,142,994	26,414
3	*Non-Discretionary subtotal*	*4,430,580*	*4,717,320*	*286,740*
4	Asset Condition	9,892,554	3,067,034	(6,825,520)
5	Non-Infrastructure	20,000	16,424	(3,576)
6	System Capacity & Performance	1,315,513	1,466,470	150,957
7	*Discretionary subtotal*	*11,228,067*	*4,549,928*	*(6,678,139)*
8	**Total Cost of Removal**	**$15,658,647**	**$9,267,248**	**($6,391,399)**

II. ISR Plan Fiscal Year 2024 Capital Spending Summary

As shown in Table 4 below, capital spending totaled $124.7 million, which was $12.4 million over the budget of $112.3 million. Spending in each of the categories is discussed in more detail below.

Table 4
Capital Spending by Category

		(a) Budget	(b) Actuals	(c) Variance Over / (Under)
1	Customer Request/Public Requirement	$27,514,000	$35,305,834	$7,791,834
2	Damage Failure	15,192,300	20,810,664	5,618,364
3	*Non-Discretionary subtotal*	*42,706,300*	*56,116,498*	*13,410,198*
4	Asset Condition	23,345,530	23,875,632	530,102
5	Non-Infrastructure	1,700,000	(1,082,494)	(2,782,494)
6	System Capacity & Performance	16,897,992	14,849,781	(2,048,211)
7	*Discretionary subtotal (excl. Large Projects)*	*41,943,522*	*37,642,919*	*(4,300,603)*
8	Large Projects Tracked Separately	27,679,000	30,966,023	3,287,023
9	*Discretionary subtotal*	*69,622,522*	*68,608,942*	*(1,013,580)*
10	**Total Capital Spending**	**$112,328,822**	**$124,725,439**	**$12,396,618**

III. ISR Plan Fiscal Year 2024 Capital Spending by Key Driver Category

e. <u>Non-Discretionary Spending</u>

a. Customer Request/Public Requirement

Capital spending for FY 2024 in the Customer Request/Public Requirement category was $35.3 million, which was $7.8 million over the budget of $27.5 million. The major drivers of this variance are:

- Spending on Third-Party Attachment projects was in a credit position as of March 31, 2024 due to the collection of customer advances for projects that will be completed in FY 2025. Costs incurred in FY 2025 will reduce customer advances.

- Spending activity, net of Distributed Generation ("DG") customer contributions, in the DG category was $2.5 million. As stated during the March 9, 2022 hearing, the Company undertook a review of DG projects. The Company reviewed $13.7 million in plant additions from FY 2013 through FY 2024 and determined that $2.2 million will remain in rate base. Please see Section IX for the DG Review Report.

- Capital spending related to meters, including the purchase of meters and work performed under the meter blanket project, totaled $1.5 million, $1.1 million under budget. As the Company transitions to AMF meters, it is anticipated that spending under these projects will continue to decrease.

- Capital spending on New Business work was $18.1 million, $1.8 million over budget. Capital spending for New Business - Residential projects, both blanket and specific project work, was $0.1 million over budget. Capital spending for New Business – Commercial projects was $1.7 million over budget due to emerging customer work that exceeded the reserves established in the budget.

- Public Requirements capital spending was $1.7 million, $0.5 million over budget. Spending under the blanket project was $0.4 million under budget. Billing for two RI Department of Transportation projects was delayed, contributing to the year's overspending. Billing for these projects is anticipated to take place in FY 2025. Billing for joint-owned pole work was $0.9 million under budget.

- Capital spending for transformers, voltage regulators, and capacitors totaled $10.9 million at year end. Supply chain challenges continue to impact pricing and availability of transformers and related equipment. These include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. The Company has sought alternate sources of supply, continued to place proactive orders to mitigate future supply gaps, and increased inventory levels to support work plans and respond to emergencies.

Detailed budget and actual spending by budget classification for the Customer Request/Public Requirement category is shown in <u>Table 5</u> below.

Table 5
Customer Request/Public Requirement Capital Spending

	(a)	(b)	(c)	(d)
	Budget Classification	**Budget**	**Actuals**	**Variance Over / (Under)**
1	Third-party Attachments	$280,000	($323,987)	($603,987)
2	Distributed Generation	1,000,000	2,513,810	1,513,810
3	Land and Land Rights	500,000	388,872	(111,128)
4	Meters & Related Work	2,605,000	1,536,504	(1,068,496)
5	New Business – Commercial	9,093,000	10,814,991	1,721,991
6	New Business – Residential	7,212,000	7,325,715	113,715
7	Outdoor Lighting	575,000	389,586	(185,414)
8	Public & Regulatory Requirement	1,249,000	1,737,993	488,993
9	Transformers & Related Equipment	5,000,000	10,921,860	5,921,860
10	Strategic DER Investments	0	490	490
11	**Customer Request / Public Requirement Spending**	**$27,514,000**	**$35,305,834**	**$7,791,834**

b. <u>Damage/Failure</u>

Capital spending in the Damage/Failure category was $20.8 million, which was $5.6 million over the budget of $15.2 million. This variance was driven by the following:

- Spending in the Overhead Line and Substation Damage/Failure Blanket projects was $11.6 million, $0.7 million over budget. Capital spending on overhead line failure-related work was $0.6 million over budget. The Substation Blanket project, which was essentially on budget, includes costs associated with the Apponaug Substation and Sprague Street transformer failures as described in more detail below.

- During FY 2022, the Westerly #2 transformer failed, and a spare transformer was installed. Due to delays in delivery of the spare transformer, minimal spending took place in FY 2024. The spare transformer was delivered in June 2024.

- In August 2022, the Nasonville Substation metal clad switchgear was damaged beyond repair due to a bus fault. Removal of the failed equipment, final engineering, and the first phase of civil construction was completed in May 2024. Underground distribution line scope and substation design changes have contributed to the increased costs. Capital spending in FY 2024 was $4.2 million.

- In 2022, the Hopkins Hill #2 transformer was taken out of service because of gassing. A mobile transformer has been installed. It is expected that the transformer teardown, visual inspection, and final report will be completed by January 2026. The first installment payment for the new transformer will be made in the first quarter of FY 2025 and the transformer is expected to be received in FY 2026.

- In July 2023, the transformer at Apponaug Substation failed. A spare transformer was used to replace the failed unit. A controlled teardown of the failed unit was performed. The inspection revealed arcing damage believed to have been caused by a lightning strike. Capital spending of $119,000 has taken place during FY 2024 and is included in the Substation Damage/Failure Blanket project.

- In May 2023, the #2 transformer at Sprague Street Substation failed. Costs associated with the immediate repair/replacement are included in the Substation Blanket project. The T3 transformer at Olneyville Substation was moved to replace the #2 Transformer at Sprague Street. The Company will not be ordering a spare transformer for either substation as both substations will be retired within the next six years.

- Actual capital spending related to storms and weather-related events was $4.8 million, $2.8 million over budget for the year. This amount includes capital spending $1.0 million for the storm on December 18, 2023. Additional information on this storm is included Attachment 2 - CY 2023 Electric Service Quality Report.

Detailed budget and actual spending for the Damage/Failure category is shown in Table 6 below.

Table 6
Damage/Failure Capital Spending

	(a) Budget Classification	(b) Budget	(c) Actuals	(d) Variance Over / (Under)
1	Damage/Failure Blanket Projects	$10,940,000	$11,633,028	693,028
2	Nasonville Substation Failure	1,092,300	4,198,412	3,106,112
3	Other Failed Assets	231,000	195,336	(35,664)
4	Reserves for Failed Assets	979,000	0	(979,000)
5	Storms and Weather Events	1,950,000	4,783,888	2,833,888
6	**Damage / Failure Spending**	**$15,192,300**	**$20,810,664**	**$5,618,364**

f. Discretionary Spending

a. *Asset Condition (without Separately Tracked Large Projects)*

Capital spending in the Asset Condition category excluding Separately Tracked Large Projects was $23.9 million, which was $0.5 million over the budget of $23.3 million. The following projects and programs were included in this category of spending:

- Capital spending for the Underground Cable Replacement program was $4.5 million, $1.0 million under budget due to prioritizing the completion of the Dyer Street Substation distribution underground line work. Both projects relied on similar constrained material and crew resources.

- Capital spending for the URD program was $6.9 million. Although the majority of the program's workplan was completed by December, work continued on one project to avoid outages in an area that was known to have a high frequency of cable faults and no backup cable. This resulted in a program overspend of $0.6 million in FY 2024.

- Capital spending on inspection and maintenance work ("I&M") was $0.4 million, under budget due to a re-prioritization of the discretionary portfolio.

- Capital spending for the Franklin Square Breaker project totaled $1.4 million. All breakers at the Franklin Square Substation have been replaced and the project is in the closeout phase.

- The project to replace 18 reclosers, approved in the FY 2024 Plan, was completed. Capital spending totaled $1.2 million and all reclosers are in service as of March 31, 2024.

- The 3763 Pole Replacement project was completed and placed into service in March 2024. Capital spending was $1.6 million, $0.8 million over budget. This project was originally budgeted in FY 2023 when material constraints resulted in the deferral of the project to FY 2024.

- In November and December 2023, the Company allocated costs associated with area studies that had accumulated in the Preliminary Survey and Investigation ("PS&I") project totaling $1.9 million. The costs were reclassified to the capital projects coming out of the area studies and appear in those projects as additional capital spending in FY 2024. The spending took place in previous years and FY 2024 activity was simply an allocation of accumulated costs. Capital projects in the Asset Condition category received $0.8 million of the allocation while the PS&I project, a project in the System Capacity & Performance spending rationale, received a $0.8 million credit. The net FY 2024 Discretionary portfolio impact is zero. Most of these projects did not have an FY 2024 budget. For additional details, please see the table included in Section (c) of this report.

b. <u>Asset Condition – Separately Tracked Large Projects</u>

During FY 2024, capital spending on the Southeast Substation, Dyer Street Substation and Providence Area projects in the Asset Condition category was $27.4 million, $3.7 million under the budget of $23.7 million.

- Capital spending on the Dyer Street Substation project totaled $2.7 million in FY 2024. The distribution line portion of the project was placed into service in February 2024. Building demolition of the existing Dyer Street Substation will begin in FY 2025 pending receipt of final permits. The total project cost forecast increased due to supply chain delays, unanticipated underground obstructions and a collapsed duct bank resulting in scope increases.

- The Company is now reporting all the Providence Study work as one project as all components are being managed collectively. The Providence Study Phase 2 project involves converting and retiring the 4.16kV load from the Geneva, Olneyville, and Rochambeau Avenue substations to 12.47kV operation. Although budgeted to begin construction in FY 2024, the resources for this project were shifted to complete the distribution line portion of the Knightsville project to accommodate the City's request. Civil work on the substation portion of Knightsville began.

- Capital spending on the Southeast Substation project totaled $0.4 million during FY 2024. The Dunnell Park substation portion of this project is complete. The majority of the assets associated with the distribution line project are in service. Building demolition was pushed from January 2024 due to material and outage delays. This project is scheduled to be substantially completed in by the end of FY 2025.

For additional information on the large project variances, please see Attachment G to the Company's FY 2024 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2024 (Docket No. 22-53-EL) filed with the PUC on May 15, 2024. A copy of this report is provided as Attachment 1.

Budget and actual spending for the Asset Condition category is shown in Table 7 below.

Table 7
Asset Condition Capital Spending

	(a)	(b)	(c)	(d)
	Budget Classification	**Budget**	**Actuals**	**Variance Over / (Under)**
1	Large Projects:			
2	Dyer Street Substation	$0	$2,725,300	$2,725,300
3	Providence LT Study - Phase 1A	0	200,318	200,318
5	Providence LT Study - Phase 1B	13,941,000	14,229,249	288,249
6	Providence LT Sudy - Phase 2,3 and 4	10,373,000	9,974,666	(398,334)
7	Southeast Substation	66,000	412,333	346,333
8	Other:			
9	Underground Cable Rplcmnt Program	5,500,000	4,531,350	(968,650)
10	URD Cable Replacement Program	6,275,530	6,896,618	621,088
11	Blanket Projects	5,220,000	4,827,201	(392,799)
12	I&M Program	3,000,000	403,144	(2,596,856)
13	Substation Breaker & Recloser Rplcmnts	1,737,000	2,577,260	840,260
14	3763 Pole Replacements	783,000	1,565,494	782,494
15	ACNW Vault Vent Blowers	600,000	713,481	113,481
16	Other Area Sudy Projects	0	666,697	666,697
17	Other Programs and Projects	230,000	1,694,386	1,464,386
18	**Asset Condition Spending**	**$47,725,530**	**$51,417,498**	**$3,691,968**

c. *Non-Infrastructure*

The Non-Infrastructure spending rationale shows a capital spending credit of $1.1 million in FY 2024. The credit is driven by the Capital Overheads project which was not fully distributed to capital projects in the previous year. The FY 2023 unallocated Capital Overhead project balance and all FY 2024 charges to the Capital Overheads project were fully distributed to capital projects in FY 2024.

Minimal spending took place on the Copper to Fiber Conversion project or in the General Equipment and Telecom projects.

Detailed budget and actual spending for the Non-Infrastructure category is shown in Table 8 below.

Table 8
Non-Infrastructure Capital Spending

	(a)	(b)	(c)	(d)
	Budget Classification	**Budget**	**Actuals**	**Variance Over / (Under)**
1	Corporate Overheads	$0	($1,142,027)	($1,142,027)
2	General Equipment	400,000	45,589	(354,411)
3	Telecommunications	300,000	1,278	(298,722)
4	Copper to Fiber Conversions	1,000,000	12,666	(987,334)
5	**Non-Infrastructure Spending**	**$1,700,000**	**($1,082,494)**	**($2,782,494)**

d. System Capacity & Performance (without Separately Tracked Large Projects)

Capital spending for FY 2024 for the System Capacity and Performance category was $14.9 million, which was $2.0 million under the FY 2024 budget of $16.9 million. This variance was driven primarily by the following projects:

- The Kingston Substation Improvement project was completed and placed into service during FY 2024. Capital spending during the year totaled $1.1 million against the budget of $1.0 million.

- Capital spending on the New Lafayette Substation project was under budget for the year. The construction start date has been delayed due to transmission outage coordination issues.

- Capital spending for the Nasonville Substation project was $2.6 million in FY 2024. Initial payments for the transformer, substation's civil work, and distribution line design took place during the year. In addition, area study costs of $0.4 million were distributed to this project from a Preliminary Survey & Investigation project. These costs are described in more detail below.

- Delays associated with the Weaver Hill Substation have resulted in an underspend of $0.9 million during FY 2024.

- The 3V0 and EMS/RTU Program work was deferred resulting in an underspend of $1.5 million.

- Capital spending on the CEMI-4 project totaled $1.2 million. Work to fix reliability issues for customers experiencing significantly poorer service than system or circuit averages took place on multiple circuits. The majority of the work was completed and was in service as of March 31, 2024. Please see Section XIII for the additional CEMI reporting required as part of the FY 2025 ISR Order.

- In FY 2024, capital spending on the System Capacity & Performance Blanket projects was over budget by $3.7 million. Work was driven by system needs identified in annual capacity and reliability reviews as well as area studies. The Company has reprioritized work to reduce outage exposure and address reliability and load issues while still focusing on delivering the discretionary portfolio on budget.

- Delays associated with Area Study project work resulted in $2.1 million underspending. A portion of this work was completed under blankets.

- During FY 2024, the Company distributed $1.9 million of costs associated with area studies that had accumulated in the Preliminary Survey and Investigation (PS&I) project. The costs were reclassified to the capital projects resulting from the area studies and appear as additional capital spending during FY 2024. The spending took place in previous years and FY 2024 activity was simply an allocation of accumulated costs. The net capital spend in FY 2024 is zero as all area studies were completed in previous years. Capital projects in the Asset Condition category received $0.8 million of the allocation. These projects did not have FY 2024 budgets. System Capacity and Performance projects, including the Nasonville Substation project noted above, received $1.1 million of the allocation.

  The table below shows the projects that received charges during FY 2024.

Allocation of Preliminary Survey & Investigation (PS&I) Costs *$000's*	
Asset Condition Projects:	
Tiverton Substation	$60
Centredale Substation	134
Apponaug Substation	27
Central Falls 4KV Conversion	120
Crossman 4KV Conversion	120
Hospital Substation Replacement	98
Kingston Substation Replacement	96
Valley Farnum 23kv conversion	120
Total Asset Condition Allocation	773
System Capacity & Performance Projects:	
Tiverton D Line	22
Weaver Hill Substation	334
Nasonville Substation	406
Coventry	111
Kenyon	101
Staples #112	120
Warren Substation	8
Total System Cap & Perf Allocation	1,101
Total PS&I Allocated	**$1,874**

e. *System Capacity & Performance - Separately Tracked Large Projects*

- During FY 2024, capital spending on the East Providence Substation project totaled $0.9 million, under budget by $0.4 million. Final engineering and procurement occurred during the year. The lead time associated with the purchase of the substation transformer was the primary driver of the FY 2024 underspend. An updated study grade estimate of $22.1 million was issued at the end of March 2024. This included an updated in-service date (2027 versus 2022), inflation, and bids received on the transformer and other similar metal-clad switchgears. The construction grade estimate for the substation will be complete in June 2025. Distribution line work was aligned with the substation and walked out of FY 2024. This walkout was offset by the Warren Substation distribution line work that was walked into FY 2024.

- During FY 2024, capital spending for the Warren Substation project was $2.5 million for both distribution line and substation work against a budget of $2.0 million. Distribution line work is ongoing. Engineering and procurement are ongoing for the substation and construction will begin in FY 2026. Overspending of the FY 2024 budget was due to revisions made to project execution plans. Warren Substation's distribution line work was walked into the FY 2024 Plan and offset by the East Providence Substation's line work which was walked out of the FY 2024 Plan.

For additional information, please see Attachment G to the Company's FY 2024 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2024 (Docket 22-53-EL) filed with the PUC on May 15, 2024. A copy of this report is attached as Attachment 1.

Budget and actual spending for the System Capacity & Performance category is shown in Table 9 below.

Table 9
System Capacity & Performance Capital Spending

	(a)	(b)	(c)	(d)
	Budget Classification	**Budget**	**Actuals**	**Variance Over / (Under)**
1	Large Projects:			
2	East Providence Substation	1,330,000	905,943	(424,057)
3	Warren Substation	1,969,000	2,518,214	549,214
4	Other Projects and Programs:			
5	Aquidneck Island	$1,038,000	$1,405,419	$367,419
6	New Lafayette Substation	750,000	258,961	(491,039)
7	Nasonville Substation	1,912,000	2,585,488	673,488
8	Tiverton Substation	108,999	215,121	106,122
9	Weaver Hill Road Substation	1,506,997	592,714	(914,283)
10	3V0	1,095,000	222,630	(872,370)
11	EMS/RTU	658,000	(15,212)	(673,212)
12	Overloaded Transformer Replmt	1,500,000	1,620,341	120,341
13	Blanket Projects	2,490,000	6,166,313	3,676,313
14	CEMI 4 Program	1,230,000	1,211,863	(18,137)
15	VVO	0	291,511	291,511
16	Other Area Study Projects	4,067,996	1,939,086	(2,128,910)
17	PS&I	100,000	(1,859,648)	(1,959,648)
18	Other	441,000	215,195	(225,805)
19	**System Capacity & Performance Spending**	**$20,196,992**	**$18,273,938**	**($1,923,054)**

f. *Advanced Metering Functionality (AMF)*

In Docket No. 22-49-EL, the Company filed its Advanced Metering Functionality ("AMF") Business Case, with the Commission on November 18, 2022. In its Order dated September 27, 2023, the Commission authorized the Company to seek recovery of capital investments through the ISR as discretionary investments capped at $153 million. Capital spending incurred prior to the ISR Fiscal Year 2025 filing is eligible for recovery. Capital spending associated with the deployment of its AMF program totaled $1.4 million in FY 2024 and shown in Table 10 below. No assets were placed in service during the year and there are no rate impacts associated with AMF in-service to date.

Table 10
AMF

	(a)	(b)	(c)	(d)
	Budget Classification	**Budget**	**Actuals**	**Variance Over / (Under)**
1	Meter Costs	$0	$16,980	$16,980
2	Network Costs	0	31,356	31,356
3	System Costs	0	1,368,008	1,368,008
4	Program Costs	0	17,701	17,701
5	**Capital Spending - AMF**	**$0**	**$1,434,045**	**$1,434,045**

IV. Vegetation Management

In FY 2024, the Company completed 100% of its work plan, 1,225 miles of distribution cycle pruning, at a cost of $13.8 million. Table 11 below provides the spending components.

Table 11
Vegetation Management O&M Spending

		(a) Budget	(b) Actuals	(c) Variance Over / (Under)
1	Cycle Pruning (Base)	$9,960,000	$10,063,082	$103,082
2	Hazard Tree	625,000	621,973	(3,027)
3	Sub-T (on & off road)	540,000	281,609	(258,391)
4	Police/Flagger Details	860,000	935,329	75,329
5	Pockets of Poor Performance	120,000	67,213	(52,787)
6	Risk Reduction - Extra	290,000	533,782	243,782
7	Core Crew (all other activities)	1,555,000	1,282,245	(272,755)
8	**Total VM O&M Spending**	**$13,950,000**	**$13,785,233**	**($164,767)**

V. Other O&M

For FY 2024, the Company completed 100% of its annual overhead structure inspection goal with an associated spend of $0.5 million. Table 12 below provides the spending components in the Other O&M category.

Table 12
Other O&M Spending

		(a) Budget	(b) Actuals	(c) Variance Over / (Under)
1	Opex Related to Capex	$400,000	$180,943	($219,057)
2	Repair & Inspections Related Costs	338,000	708,453	370,453
3	System Planning & Protection Coordination Study	25,000	0	(25,000)
4	VVO/CVR Program	400,000	255,000	(145,000)
5	**Total I&M and Other O&M Spending**	**$1,163,000**	**$1,144,396**	**($18,604)**

For additional information about the I&M program, please see the Company's FY 2024 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2024 (Docket No. 22-53-EL) filed with the PUC on May 15, 2024. A copy of this report is attached as Attachment 1.

VI. Reliability Performance

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance metrics in CY 2023, with SAIFI of 0.769 against a target of 1.05, and SAIDI of 52.62 minutes, against a target of 71.9 minutes. For additional information on reliability and major event days, please refer to the 2023 Service Quality Report filed under Docket No. 3628 on May 1, 2024. A copy is included in this report as Attachment 2.

VII. FY 2025 Five Year Budget with Details and FY 2024 Actuals

In Docket No. 23-48-EL, the Company provided a five year budget plan with a forecast for FY 2024 spending as Attachment 3, Bates pages 84-86.

The five year budget plan with actual FY 2024 spending is shown in the attached.

FY 2025 Five-Year Budget witu Details and FY 2024 Actuals
$000's

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			Docket 22-53-EL		**5 Year Investment Plan - Capital Spending**					**Major Project - Details**						
Line Number	**Spending Rationale**	**Category**	**FY 2024 Budget**	**FY 2024 Actuals**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**Major Project - Current Puase**	**Current Sanction - CAPEX only**	**Initial Estimate - CAPEX only**	**Date of Last Sanction**	**Est'd Constr Start**	**Est'd Constr End**	**Capital Spending turougu FY 2023**
1	**Non-Discretionary**															
	Customer Request /															
2	Public Requirement	New Business - Commercial	9,093	10,815	9,366	9,647	9,937	10,235	10,542							
3		New Business - Residential	7,212	7,326	7,428	7,651	7,880	8,117	8,361							
4		Public Requirements	1,249	1,738	3,140	3,234	3,331	3,431	3,531							
5		Transformers and Related Equipment	5,000	10,922	8,000	8,000	8,000	8,000	8,000							
6		Meters and Meter Work	2,605	1,537	2,533	430	100	100	100							
7		Distributed Generation	1,000	2,514	1,000	1,000	1,000	1,000	1,000							
8		Third Party Attachments	280	(324)	288	297	306	315	324							
9		Land and Land Rights	500	389	515	530	546	562	579							
10		Outdoor Lighting	575	390	592	610	628	647	666							
11	**Total Customer Request/Public Requirement**		**27,514**	**35,305**	**32,862**	**31,399**	**31,728**	**32,407**	**33,103**							
12	Damage / Failure	Damage /Failure	10,940	11,633	11,268	11,606	11,954	12,313	12,682							
13		Reserves	979	-	1,008	1,038	1,070	1,102	1,135							
14		Failed Assets	1,323	4,394	2,537	1,972	-	-	-							
15		Storms	1,950	4,784	3,000	3,000	3,000	3,000	3,000							
16	**Total Damage/Failure**		**15,192**	**20,811**	**17,813**	**17,616**	**16,024**	**16,415**	**16,817**							
17	**Total Non-Discretionary**		**42,706**	**56,116**	**50,675**	**49,015**	**47,752**	**48,822**	**49,921**							

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			Docket 22-53-EL		5 Year Investment Plan - Capital Spending					Major Project - Details						
Line Number	Spending Rationale	Category	FY 2024 Budget	FY 2024 Actuals	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Major Project - Current Puase	Current Sanction - CAPEX only	Initial Estimate - CAPEX only	Date of Last Sanction	Est'd Constr Start	Est'd Constr End	Capital Spending turougu FY 2023
1	**Discretionary**															
2	Asset Condition															
3	Separately Tracked Major	Dyer Street Substation	-	2,725	15	-	-	-	-	Construction	$10,658	$10,842	Apr-21	Sep-21	FY 2025	$14,651
4		Admiral St 12 KV Substation	-	-	5,513	2,500	-	-	-	Construction	$12,831	$12,831	Aug-21	Sep-21	FY 2026	$2,731
5		Providence Area LT Study Projects (Ph 1A,1B,2,4)	24,314	24,404	-	-	-	-	-	--	--	--	--	--	--	--
6		Kingston Equipment Replacement	-	-	400	3,361	8,403	1,681	2,961	Study Phase	--	$16,805	--	Oct-25	FY 2029	$0
7		Phillipsdale Substation D Sub	-	-	100	5,728	7,240	1,448	324	Study Phase	--	$6,025	--	Oct-25	FY 2029	$0
8		Apponaug Substation	-	-	150	1,120	1,980	1,750	700	Study Phase	$5,700	$3,800	Jul-23	FY 2026	FY 2029	$0
9		Hospital #146 Equipment Replacement	-	-	320	2,064	2,680	296	-	Study Phase	$5,360	$5,359	Dec-23	FY 2026	FY 2028	$0
10		Merton #51 Equipment Replacement	-	-	-	816	2,449	4,082	816	Study Phase	--	$8,164	--	FY 2027	FY 2029	$0
11		Southeast Substation	66	412	-	-	-	-	-	Construction	$11,244	$9,000	Jun-19	Oct-19	FY 2025	$15,198
12		Auburn 115/12.4kV Substation (D-Sub)	-	-	-	-	832	1,663	4,989	Study Phase	--	$6,590	--	FY 2028	FY 2029	$0
13	Subtotal - Separately Track Major Projects		24,380	27,542	6,498	15,589	23,583	10,919	9,790							
14	Other	Underground Cable Replacement	5,500	4,531	5,500	6,000	6,000	6,000	6,500							
15		URD Cable Replacement	6,276	6,897	5,000	5,411	5,723	5,823	5,500							
16		Blanket Projects	5,220	4,827	6,177	6,338	6,504	6,676	6,850							
17		I&M	3,000	403	1,530	1,530	1,530	1,530	1,530							
18		Substation Spare Transformers	-	-	540	2,480	7,436	8,186	6,825							
19		Substation Breakers & Reclosers	437	1,416	196	440	-	-	-							
20		Other Area Study Projects - BSVS	-	1,150	781	1,556	2,457	2,280	1,156							
21		Other Area Study Projects - CRIE	-	27	50	75	35	293	315							
22		Other Area Study Projects - CRIW	-	-	1,883	6,317	10,196	3,730	390							
23		Other Area Study Projects - East Bay	-	-	100	505	570	570	190							
24		Other Area Study Projects - Newport	-	197	446	1,189	802	-	-							
25		Other Area Study Projects - NWRI	-	137	500	3,007	2,725	1,432	250							
26		Other Area Study Projects - Providence	-	-	492	5,396	6,575	4,630	4,630							
27		Other Area Study Projects - SCW	-	-	-	-	-	1,029	2,297							
28		Tiverton Substation	-	61	75	393	786	786	393							
29		Providence Area LT Supply & Distrib Study	-	-	20,382	10,580	7,064	-	-							
30		Reserve	-	-	-	1,000	1,000	1,000	1,000							
31		Batteries / Chargers	230	55	195	387	319	100	-							
32		Recloser Replacements	1,300	1,161	-	-	-	-	-							
33		UG Improvements and Other	1,383	3,013	700	565	-	-	-							
34	Subtotal - Other Projects and Programs		23,346	23,876	44,547	53,169	59,722	44,065	37,826							
35	**Total Asset Condition**		**47,726**	**51,417**	**51,045**	**68,758**	**83,305**	**54,984**	**47,617**							
36	Non-Infrastucture															
37		General Equip & Telecom Blanket	700	47	712	724	737	750	764							
38		Capital Overheads	-	(1,142)												
39		Verizon Copper to Fiber	1,000	13	180	75	-	-	-							
40	**Total Non-Infrastructure**		**1,700**	**(1,082)**	**892**	**799**	**737**	**750**	**764**							

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			Docket 22-53-EL		**5 Year Investment Plan - Capital Spending**					**Major Project - Details**						
Line Number	**Spending Rationale**	**Category**	**FY 2024 Budget**	**FY 2024 Actuals**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**Major Project - Current Puase**	**Current Sanction - CAPEX only**	**Initial Estimate - CAPEX only**	**Date of Last Sanction**	**Est'd Constr Start**	**Est'd Constr End**	**Capital Spending turougu FY 2023**
1	System Capacity & Performance															
2	Separately Tracked Major	East Providence Substation (D Sub + D Line)	1,330	906	-	-	-	-	-	--	--	--	--	--	--	--
3		East Providence Substation (D Sub)	-	-	2,685	2,309	2,952	-	-	Preliminary Eng'g	$6,000	$6,000	Feb-17	Apr-24	Oct-26	$892
4		Warren Substation (D Sub + D Line)	1,969	2,518	-	-	-	-	-	--	--	--	--	--	--	--
5		Chase Hill Second Half of Station	-	-	-	1,006	2,012	1,006	1,006	Study Phase	--	$5,030	--	FY 2027	FY 2029	$0
6		Nasonville #127 Sub (D-Sub)	-	-	3,566	3,100	489	-	-	Study Phase	$10,786	$13,325	Jul-23	FY 2026	FY 2027	$0
7	Subtotal - Separately Track Major Projects		3,299	3,424	6,251	6,415	5,453	1,006	1,006							
8	Other	Aquidneck Island	1,038	1,405	-	-	-	-	-							
9		New Lafayette Substation	750	259	910	5,886	151	-	-							
10		Warren Substation	-	-	1,800	2,943	747	111	-							
11		Nasonville Substation (D Sub + D Line)	1,912	2,585	-	-	-	-	-							
12		East Providence Substation (D Line)	-	-	3,600	2,700	2,051	-	-							
13		Weaver Hill Road Substation	1,507	593	1,105	3,054	3,475	2,496	1,229							
14		3V0	1,095	223	186	540	-	-	-							
15		EMS/RTU	658	(15)	135	1,147	2,350	750	-							
16		Overloaded Transformer Replcmts	1,500	1,620	1,500	1,500	1,500	1,500	1,500							
17		Blanket Projects	2,490	6,166	2,605	2,725	2,851	2,983	3,072							
18		Other Area Study Projects - BSVS	400	127	680	681	968	-	-							
19		Other Area Study Projects - CRIW	1,371	794	1,441	1,125	1,125	675	-							
20		Other Area Study Projects - East Bay	-	-	84	378	378	-	-							
21		Other Area Study Projects - Newport	-	-	793	976	461	-	-							
22		Other Area Study Projects - NWRI	1,933	914	108	128	-	-	-							
23		Other Area Study Projects - SCE	-	-	1,684	6,404	333	-	-							
24		Other Area Study Projects - SCW	364	104	927	4,101	3,909	2,576	1,147							
25		Tiverton D-Line	109	215	328	656	656	328	440							
26		Reserve	-	-	-	1,000	1,000	1,000	1,000							
27		CEMI-4	1,230	1,212	1,230	1,230	1,230	1,230	-							
28		ADMS/DERMS Advanced	-	-	-	-	3,159	1,568	-							
29		DER Monitor/Manage	-	-	-	-	2,288	4,043	-							
30		Electromech Relay Upgrades	-	-	1,234	603	1,267	2,513	1,263							
31		Fiber Network	-	-	200	-	-	-	-							
32		VVO - Smart Capacitors and Regulators	-	292	400	8,439	6,701	6,701	6,701							
33		Mobile Substation	-	-	1,278	3,834	7,668	-	-							
34		Other projects and programs	541	(1,644)	478	100	100	100	100							
35	Subtotal - Other Projects and Programs		16,898	14,850	22,706	50,150	44,369	28,575	16,452							
36	**Total System Capacity & Performance**		**20,197**	**18,274**	**28,957**	**56,565**	**49,822**	**29,581**	**17,458**							

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			Docket 22-53-EL		**5 Year Investment Plan - Capital Spending**					**Major Project - Details**						
Line Number	**Spending Rationale**	**Category**	**FY 2024 Budget**	**FY 2024 Actuals**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**Major Project - Current Puase**	**Current Sanction - CAPEX only**	**Initial Estimate - CAPEX only**	**Date of Last Sanction**	**Est'd Constr Start**	**Est'd Constr End**	**Capital Spending turougu FY 2023**
1	**Total Discretionary excluding AMF**		**69,623**	**68,609**	**80,894**	**126,122**	**133,864**	**85,315**	**65,839**							
2	Advanced Metering Functionality															
3		Meter Costs	-	17	28,725	61,795	4,212	-	-							
4		Network Costs	-	31	4,479	8,374	1,985	-	-							
5		System Costs	-	1,368	11,487	13,280	7,597	-	-							
6		Program Costs	-	18	3,502	3,502	1,751	-	-							
7	**Total AMF**		**-**	**1,434**	**48,192**	**86,950**	**15,544**	**-**	**-**							
8	**Total Discretionary including AMF**		**69,623**	**70,043**	**129,086**	**213,073**	**149,408**	**85,315**	**65,839**							
9	**Total Capital Spending including AMF**		**112,329**	**126,159**	**179,761**	**262,088**	**197,160**	**134,137**	**115,759**							
10	**Total Capital Spending excluding AMF**		**112,329**	**124,725**	**131,569**	**175,137**	**181,616**	**134,137**	**115,759**							
				-												
11	**O&M Spend**															
12		Vegetation Management	13,950	13,785	13,075											
13		I&M - Opex Related to Capex	400	181	200											
14		I&M - Inspections & Replairs Related Costs	338	708	500											
15		System Planning & Protection Coordination Study	25	-	-											
16		VVO/CRV	400	255	365											
17	**Total O&M**		**15,113**	**14,930**	**14,140**											

VIII. Customers Experiencing Multiple Interruptions (CEMI) Reporting

In its Report and Order dated December 31, 2023, the Commission directed the Company to include in its FY 2024 Electric ISR Reconciliation Filing and future ISR Plan and Reconciliation filings certain information about work performed on CEMI-4 feeders selected for inclusion in the FY 2024 ISR Plan. This information is shown in the attached.

FY 2024 CEMI 4 Feeder Information

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line Number	**Feeders Selected**	**Rolling 12 Month CEMI n**	**Highest CEMI Count in the previous rolling 12 months**	**Why was the feeder prioritized over another with a similar CEMI?**	**What was the problem identified?**	**Alternative solutions identified?**	**Work Performed**	**CAPEX $**	**Why did the Company choose the solution implemented?**	**Funded Elsewhere (Y or N)**	**If Yes, where and how will benefits be tracked?**
1	112W44	8	9	Note 1	Note 2	Note 3	Install 1 relcoser, 3 cutout mounted reclosers, small sections of reconductoring and animal guards	$155,871	Note 4	N	Note 5
2	127W40	7	9	Note 1	Note 2	Note 3	Install 2 reclosers, 3 cutout mounted reclosers, and replace 1 pole.	$274,219	Note 4	N	Note 5
3	155F8	10	10	Note 1	Note 2	Note 3	Install 1 cutout mounted recloser, 1 set of line fuses, and insulators	$16,022	Note 4	N	Note 5
4	34F1	8	8	Note 1	Note 2	Note 3	Install 2 reclosers	$97,496	Note 4	N	Note 5
5	54F1	11	11	Note 1	Note 2	Note 3	Install 7 cutout mounted reclosers, 6 sets of line fuses, and various deteriorated pole replacements	$254,690	Note 4	N	Note 5
6	63F6	9	8	Note 1	Note 2	Note 3	Install 7 cutout mounted reclosers and small sections of reconductoring	$148,365	Note 4	N	Note 5
7	68F1	13	8	Note 1	Note 2	Note 3	Install 2 reclosers, 4 cutout mounted reclosers, and 1 loadbreak	$143,492	Note 4	N	Note 5

Note 1 Feeders were prioritized based on a combined ranking that includes the current year CEMI and the number of CEMI-4 customers on the feeder in the previous three years. The program also considers input from the operations department as well as other pending capital projects.

Note 2 The leading causes of outages that contribute to high CEMI numbes are trees, animal contact, lighting, motor vehicle accidents, and deteriorated equipment. These are common to the problems that contribute to circuit and system reliability statistics, except major storm events are included .

Note 3 Due to the specific locational and cause characteristics of the events, a typical alternative analysis was not considered warranted. Instead, the solutions are based on common field engineering knowledge, and the advancement of lowest cost solutions. For example, if events indicate an animal contract issue, an alternative analysis is not warranted to provide confidence that the low cost of installing animal guards is the best solution.

Note 4 The Company chose the solutions based on reviewing the outage trends that contributed to customer outages, considering the lowest cost solutions first. In most cases more than one solution was recommended.

Note 5 If a solution was identified during CEMI analysis that is related to another program, the team would determine whether the recommended work is planned to be complete in the existing programs (i.e. Vegetation Management). If it is not in the other program's plan, it would be completed under the CEMI program. Program benefits will be tracked by reviewing the Company’s overall CEMI-4 performance and the CEMI performance of circuits in the program annually.

IX. Distribution Generation Report

1) Overview

This report summarizes the results of the distributed generation ("DG") projects review undertaken by the Company as stated in the FY 2023 ISR Hearing on March 9, 2022 and the process improvements implemented. In addition, this report complies with the directives issued by the Public Utilities Commission most recently from the Open Meeting that occurred on March 28, 2024 for Docket No. 23-48 EL, the FY 2025 Annual Electric ISR Plan. The directive stated that the Company should include in the FY 2024 Annual Reconciliation filing its review of the allocation of customer contributions to the proper cost categories all distributed generation projects for which the customer contribution did not cover the full cost of the project; the reasons why; and the impact on rate base and the associated revenue requirement.

Between FY 2013 and FY 2022, the Company included plant additions of $11.8 million in rate base. The Company began a review of these projects and removed $10.6 million of plant additions in the FY 2023 Annual Reconciliation Filing, leaving $1.2 million in rate base. Customers were credited for the amount previously included in rate base in the FY 2023 Annual Reconciliation Filing. As of FY 2024, an additional $1.0 million has been added, totaling $2.2 million.

2) Review Process

Initial Review: The Company began the review by selecting a sample of projects for review based off largest plant additions from FY 2013 through FY 2021, totaling approximately $4.8 million. The Company completed an in depth look at each project, reviewing information including the Impact Study, Interconnection Service Agreement ("ISA"), Final Accounting Report, and construction notes along with detailed actuals including Contributions in Aid of Construction ("CIAC") payments.

The Company categorized the findings into four scenarios with the following resulting actions:

<table>
<tr><th>#</th><th>Finding</th><th>Resulting Action</th></tr>
<tr><td>1</td><td>Refund was issued to the customer</td><td rowspan="2">Plant Additions removed from revenue requirement and expensed.</td></tr>
<tr><td>2</td><td>CIAC was incorrectly allocated.</td></tr>
<tr><td>3</td><td>System Improvement was completed as part of the scope of work.</td><td rowspan="2">Plant Additions remain in revenue requirement.</td></tr>
<tr><td>4</td><td>Actual costs exceeded the estimate and could not be collected from the customer due to the timing of the cost increases and notification requirements outlined in R.I.P.U.C. No. 2258 (the “Tariff”).[2]</td></tr>
</table>

For the last finding in the table above, the Tariff does not include language that expressly allows or expressly prohibits the Company from collecting from all ratepayers costs associated with projects where the actual costs exceeded the estimate and the difference could not be collected from the customer.

The interconnection statute, however, provides that “[t]he estimate may be relied upon by the applicant for purposes of determining the expected cost of interconnection, but the distribution company may not be held liable or responsible if the actual costs exceed the estimate as long as the estimate was provided in good faith and the interconnection was implemented prudently by the electric distribution company.” See R.I. Gen. Laws § 39-26.3-2 (definition of an Impact Study).

[2] See Exhibit I of the Tariff (Interconnection Service Agreement), Page 101, Section 5.1 entitled Cost or Fee Adjustment Procedures which provides that: “The Company will, in writing, advise the Interconnecting Customer in advance of any expected cost increase for work to be performed up to a total amount of increase of 10% only. Any such changes to the Company’s costs for the work shall be subject to the Interconnecting Customer’s consent. The Interconnecting Customer shall, within thirty (30) days of the Company’s notice of increase, authorize such increase and make payment in the amount up to the 10% increase cap, or the Company will suspend the work and the corresponding agreement will terminate.”

Accordingly, as long as the Company's estimate was made in good faith and the interconnection was implemented prudently, the Company is not responsible for System Modification costs that exceed the cost cap for the Interconnecting Customer.

Per the Tariff, the Company has the ability to advise the Interconnecting Customer of expected cost increases for work to be performed but only up to a total increase amount of 10%. For increases up to 10%, the Interconnecting Customer must be provided with written advance notice of the expected cost increase. Typically, cost increases are not expected in advance of performing the work, making it practically impossible for the Company to provide advance written notification and solicit an Interconnecting Customer's consent prior to work being performed.

Accordingly, there are projects where the actual costs exceed the estimate and the difference was not collected from the Interconnecting Customer either because of the 10% limit or because the Company could not provide the Interconnecting Customer with written advance notice due to the timing of when the work was performed.

When taking into account both R.I. Gen. Laws § 39-26.3-2 and the above-referenced Tariff provisions, it is appropriate to recover the difference from distribution customers.

The initial review led to $1.2 million remaining in service and was reported on during FY 2023 Annual Reconciliation Filing. The remaining projects were expensed.

Full Review: Due to the results from the initial set, the Company decided to review all of the remaining DG plant additions from FY 2013 through FY 2022. All plant additions, besides the $1.2 million, were removed from rate base in the FY 2023 Annual Reconciliation Filing and reviewed during FY 2024. No plant additions from FY 2023 were included in the FY 2023 Annual Reconciliation Filing.

The full review concluded that in total, $2.2 million should be included in rate base. This included 10 different projects. Two projects included system improvements and the remainder were related to higher spending than the CIAC collected. These projects were included in the FY 2024 Annual Reconciliation Revenue Requirement calculation.
In total, the Company has expensed $5.3 million to date related to completed projects. These projects either had refunded the customer, CIACs incorrectly applied or did not have sufficient information to be placed back into service.

This review also found that a significant portion of projects with plant balances were included in the revenue requirement but had not been reconciled yet. These balances will not be put into service until the projects are reconciled and confirmed to be system improvements or true overspends which occurred during construction.

3) **Process Changes**

The Company has reflected on lessons learned and process improvements that will be implemented as new projects are created and reconciliations continue. These include, but are not limited to:

- Plant additions were included for projects in ISR Reconciliation Filings that had not been completed or reconciled. Plant additions for DG projects are now not put into service or included in ISR rate base until project reconciliations are complete and explanations are documented.

- Multiple projects that were reviewed found that CIACs were allocated to the incorrect projects or were applied to the wrong cost type (i.e. Opex instead of Capex). Actuals will be reviewed by the project team monthly to ensure CIACs are being recorded appropriately.

- It was difficult to understand why projects overspent the estimated amount, primarily due to lack of documentation. There will be cadenced meetings between Engineering, Project Management, Customer Energy Integration, Finance and Regulatory teams to communicate project status, explain cost variances and update project forecasts. A portfolio tracker will also be created to document these updates.

- Project setup in the Company's internal systems did not seem to be uniform. Some projects had multiple work orders for a particular scope while others only had one work order. This led to work orders being missing from the reconciliation process. The process to set up projects needs to be uniform to ensure all of the work is being captured in reconciliations.

- The Company's engineering team continually reviews costs at the end of projects to improve project estimates, however, estimating templates are not easy to compare with the actuals to understand what categories of spend had variances. Estimating templates need to be updated so that actuals can be easily comparable at reconciliation.

Attachment 1

Quarterly Report for the Fourth Quarter Period Ending March 31, 2024

Andrew S. Marcaccio, Counsel
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Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

May 15, 2024

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 – FY2024 Electric Infrastructure, Safety, and Reliability Plan Quarterly Update – Fourth Quarter Ending March 31, 2024

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy, I have enclosed an electronic version of the Company's fiscal year (FY) 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan quarterly update for the fourth quarter ending March 31, 2024. Pursuant to the provisions of the approved FY 2018 Electric ISR Plan, the Company committed to providing quarterly updates on the progress of its Electric ISR program to the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers.

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

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Docket 22-53-EL Service List

Electric Infrastructure, Safety, and Reliability Plan
ISR Plan Fiscal Year 2024 – Fourth Quarter Update
For the Fiscal Year Ending March 31, 2024

EXECUTIVE SUMMARY

As shown in Attachment A, The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") spent \$124.7 million for capital projects against a budget of \$112.3 million during the ISR Plan Fiscal Year 2024 (April 1, 2023 through March 31, 2024, or "FY 2024") for its electric infrastructure, safety, and reliability ("ISR") plan. Non-Discretionary spending was \$56.1 million, \$13.4 million over budget. Discretionary spending, including the separately tracked large projects, was \$68.6 million, \$1.0 million under budget. For FY 2024, capital spending was over budget due to non-discretionary spending related to transformers purchases and failed assets. Spending in each of these categories is addressed in more detail below.

I. FY 2024 Capital Spending by Key Driver Category

1. Non-Discretionary Spending

a. *Customer Request/Public Requirement*

During FY 2024, capital spending in the Customer Request/Public Requirement category was $35.3 million, which was $7.8 million over the budget of $27.5 million.

The major drivers were:

- Spending on Third-Party Attachment projects was in a credit position as of March 31, 2024 due to the collection of customer advances for projects that will be completed in FY 2025.

- Distributed Generation ("DG") capital spending activity, net of DG customer contributions, was $2.5 million in FY 2024. Charges that were incurred in the last quarter of the fiscal year are under review, and if necessary, adjustments will be made in the Annual Reconciliation filing. The Company continues to review and reconcile DG projects and is anticipating that capital spending will continue to be reduced by customer advances during the reconciliation process. The Company is finalizing a report to be included in the FY 2024 Annual Reconciliation outlining the review of all distributed generation projects for which the customer contribution did not cover the full cost of the project; the reasons why; and the impact on rate base and the associated revenue requirement.

- Capital spending on New Business work was $18.1 million, $1.8 million over budget. New Business Residential capital spending, both blanket and specific project work, was $0.1 million over budget. New Business Commercial capital spending was $1.7 million over budget due to emerging customer work that exceeded the reserves established in the budget.

- Public Requirements capital spending was $1.7 million, $0.5 million over budget. Spending under the blanket project was $0.4 million under budget. Billing for RI Department of Transportation was delayed, contributing to the year's over spend. Billing for these projects is anticipated to take place in FY 2025. Joint-owned pole billing was $0.9 million under budget.

- Capital spending related to meters, including the purchase of meters and work performed under the meter blanket project, totaled $1.5 million, $0.9 million under budget. As the Company transitions to AMF meters, it is anticipated that spending under these projects will continue to decrease. The Landline Meter

Replacement project, budgeted for $0.1 million in FY 2024, was cancelled. Detailed meter and instrument purchases are shown in Attachment H to this report.

- Capital spending for transformers, voltage regulators, and capacitors totaled $10.9 million at year end. Supply chain challenges continue to impact pricing and availability of transformers and related equipment. These include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. During 2023, the Company sought alternate sources of supply, continued to place proactive orders to mitigate future supply gaps, and increased inventory levels to support work plans and respond to emergencies.

b. Damage/Failure

During FY 2024, capital spending in the Damage/Failure category was $20.8 million, which was $5.6 million over the $15.2 million budget. The major drivers were:

- Spending in the Overhead Line and Substation Damage/Failure Blanket projects was $11.6 million, $0.7 million over budget. Capital spending on overhead line failure-related work was $0.6 million over budget. The Substation Blanket project, which was essentially on budget, includes costs associated with the Apponaug Substation and Sprague Street transformer failures as described in more detail below.

- Actual capital spending related to storms and weather-related events was $4.8 million, $2.8 million over budget for the year. This amount includes capital spending of $0.9 million for the weather event on September 13, 2023 and $1.0 million for the storm on December 18, 2023.

- During ISR Plan Year 2022, the Westerly #2 transformer failed, and a spare transformer was installed. Due to delays in delivery of the spare transformer, minimal spending took place in FY 2024. Delivery of the spare transformer is scheduled for June 2024.

- In August 2022, the Nasonville Substation metal clad switchgear was damaged beyond repair due to a bus fault. Removal of the failed equipment has been completed. Final engineering and the first phase of civil construction will be completed in May 2024. Underground distribution line scope and substation design changes have contributed to the increased costs. Capital spending in FY 2024 was $4.2 million.

- In 2022, the Hopkins Hill #2 transformer was taken out of service because of gassing. A mobile transformer has been installed. It is expected that the transformer teardown, visual inspection, and final report will be completed by January 2026. The first installment payment for the new transformer will be made in the first quarter of FY 2025 and the transformer is expected to be received in FY 2026.

- In July 2023, the transformer at Apponaug Substation failed. A spare transformer was used to replace the failed unit. A controlled teardown of the failed unit was performed. The inspection revealed arcing damage believed to have been caused by a lightning strike. Capital spending of $119,000 has taken place during FY 2024 and is included in the Substation Damage/Failure Blanket project.

- In May 2023, the #2 transformer at Sprague Street Substation failed. Costs associated with the immediate repair/replacement are included in the Substation Blanket project. The T3 transformer at Olneyville Substation was moved to replace the #2 Transformer at Sprague Street.

2. <u>Discretionary Spending</u>

a. <u>Asset Condition (Without Separately Tracked Large Projects)</u>

During FY 2024, capital spending in the Asset Condition category (excluding separately tracked large projects) was $23.9 million, $0.5 million over the $23.3 million budget. The major drivers in this category are as follows:

- Capital spending on inspection and maintenance work (“I&M”) was $0.4 million, under budget due to a re-prioritization of the discretionary portfolio.

- Capital spending for the Underground Cable Replacement program was $4.5 million, $1.0 million under budget due to prioritizing the completion of the Dyer Street Substation distribution underground line work. Both projects relied on similar constrained material and crew resources.

- Capital spending for the URD program was $6.9 million. Although the majority of the program’s workplan was completed by December, work continued on one project to avoid outages in an area that was known to have a high frequency of cable faults and no backup cable. This resulted in an overall program overspend of $0.6 million in FY 2024.

- Capital spending for the Franklin Square Breaker project totaled $1.4 million. All breakers at the Franklin Square Substation have been replaced.

- After delays in 2023, the 3763 Pole Replacement project was completed and placed into service in March 2024. Capital spending was $1.6 million, $0.8 million over budget. This project was originally budgeted in FY 2023 when material constraints resulted in the deferral of the project to FY 2024.

- The project to replace 18 reclosers, approved in the FY 2024 Plan, was completed. Capital spending totaled $1.2 million and all reclosers are in service as of March 31, 2024.

- In November and December 2023, the Company allocated costs associated with area studies that had accumulated in the Preliminary Survey and Investigation ("PS&I") project totaling $1.9 million. The costs were reclassified to the capital projects coming out of the area studies and appear in those projects as additional capital spending in FY 2024. The spending took place in previous years and FY 2024 activity was simply an allocation of accumulated costs. Capital projects in the Asset Condition category received $0.8 million of the allocation while the PS&I project, a project in the System Capacity & Performance spending rationale, received a $0.8 million credit. The net FY 2024 Discretionary portfolio impact is zero. Most of these projects did not have an FY 2024 budget. For additional details, please see the table included in Section (c) of this report.

b. Non-Infrastructure

In Attachment A – Capital Spending by Spending Rationale, the Non-infrastructure spending rationale shows a capital spending credit of $1.1 million in FY 2024. The credit is driven by the Capital Overheads project which was under-allocated in the previous year. The unallocated FY 2023 costs and all FY 2024 charges to the Capital Overheads project were fully distributed to capital projects in FY 2024.
Minimal spending took place on the Copper to Fiber Conversion project or in the General Equipment and Telecom projects.

c. System Capacity and Performance (Without Separately Tracked Large Projects)

During FY 2024, capital spending for the System Capacity and Performance category was $14.9 million, $2.0 million under the $16.9 million budget. The major drivers in this category were as follows:

- The Kingston Substation Improvement project was completed and placed into service during FY 2024. Capital spending during the year totaled $1.1 million against a budget of $1.0 million.

- Capital spending on the New Lafayette Substation project was under budget for the year. The construction start date has been delayed due to transmission outage coordination issues.

- Capital spending on the CEMI-4 project totaled $1.2 million. Work to fix reliability issues for customers experiencing significantly poorer service than system or circuit averages took place on multiple circuits. The majority of the work was completed and was in service as of March 31, 2024.

- Delays associated with the Weaver Hill Substation have resulted in an underspend of $0.9 million for FY 2024. Planned work has been deferred until FY 2025 for portfolio management purposes.

- Capital spending for the Nasonville Substation project (D Sub and D Line) was $2.6 million during FY 2024. Initial payments for the transformer, substation's civil work, and distribution line design took place during the year. In addition, area study costs of $0.4 million were distributed to this project from a Preliminary Survey & Investigation project. These costs are described in more detail below. For FY 2025 ISR budgetary and reporting purposes, the Nasonville Substation D Sub project (# CRI3027) has been identified as a Separately Tracked Major Project. The Nasonville Substation D Line project (#CRI3028) will continue to be classified as a System Capacity & Performance project for budgetary and reporting purposes.

- In FY 2024, capital spending on the System Capacity & Performance Blanket projects were over budget by $3.7 million. Work was driven by annual capacity and reliability reviews as well as area studies. The Company has reprioritized work to reduce outage exposure and address reliability and load issues while still focusing on delivering the discretionary portfolio on budget. The Company continues to review all work to ensure it is appropriately categorized.

- During FY 2024, the Company distributed $1.9 million of costs associated with area studies that had accumulated in the Preliminary Survey and Investigation (PS&I) project. The costs were reclassified to the capital projects coming out of the area studies and appear as additional capital spending during FY 2024. The spending took place in previous years and FY 2024 activity was simply an allocation of accumulated costs. The net capital spend in FY 2024 is zero as all area studies were completed in previous years. Capital projects in the Asset Condition category received $0.8 million of the allocation. These projects did not have FY 2024 budgets. System Capacity and Performance projects, including the Nasonville Substation project noted above, received $1.1 million of the allocation.

The table below shows the projects that received charges during FY 2024:

Allocation of Preliminary Survey & Investigation (PS&I) Costs *$000's*	
Asset Condition Projects:	
Tiverton Substation	$60
Centredale Substation	134
Apponaug Substation	27
Central Falls 4KV Conversion	120
Crossman 4KV Conversion	120
Hospital Substation Replacement	98
Kingston Substation Replacement	96
Valley Farnum 23kv conversion	120
Total Asset Condition Allocation	773
System Capacity & Performance Projects:	
Tiverton D Line	22
Weaver Hill Substation	334
Nasonville Substation	406
Coventry	111
Kenyon	101
Staples #112	120
Warren Substation	8
Total System Cap & Perf Allocation	1,101
Total PS&I Allocated	**$1,874**

d. Advanced Metering Functionality (AMF)

The Company has included the capital spending associated with the deployment of its AMF program described in Docket No. 22-49-EL as a separate Discretionary category in its Proposed FY 2025 ISR Plan. Capital spending of $1.4 million took place during FY 2024 in the following areas:

Fiscal Year Ending March 31, 2024	
	Actuals $000's
Meter Costs	$17
Network Costs	31
System Costs	1,368
Program Costs	18
Capital Spending - AMF	**$1,434**

Actual capital spending was less than the amount forecasted in the Third Quarter ISR report due to a shift in the Transition Services Agreement ("TSA") exit date from May 2024 to August 2024.

e. Separately Tracked Large Projects

During FY 2024, capital spending on the following Large Projects is tracked and reported separately: Southeast Substation, Dyer Street Substation, Providence Study projects, East Providence Substation, and Warren Substation. Each project is discussed in Attachment G.

f. Large Project Variances

The Company provides explanations for large projects[1] with variances that exceed +/-10% of the Plan Year budget in quarterly reports. These projects represent $9.0 million of the 2024 budget of $112.3 million. This project information is provided in Attachment E.

g. New Distribution System Technology Update

The Quarterly Updates include an explanation of new technologies the Company is exploring to assist in distribution system planning, particularly as they relate to the integration of DERs or to provide additional visibility on the distribution system. The Company continues to increase its use of Python Scripting to improve automation in CYME as well as other computer programs. For example, the grid modernization analysis utilized Python scripts for electric vehicle, electric heat pump, and DG placement within the CYME models.

3. Investment Placed-in-Service

During FY 2024, $97.2 million of plant additions were placed in service, which was over the Plan's target of $89.0 million primarily driven by additions related to the Dyer Street Substation distribution line project. Details by spending rationale are included in Attachment B.

4. Vegetation Management

During FY 2024, the Company completed 1,225 miles of distribution mileage cycle pruning. The planned feeders were adjusted during the year, slightly affecting the overall miles completed. The Company spent $13.8 million during the year.

[1] Large projects are defined as projects exceeding $1.0 million in total project cost.

The Company agreed to provide additional information on its vegetation management program that allows for the disaggregation of cycle pruning and the enhanced hazard tree management program. A plan to collect data was provided in a May 15, 2023 letter to the Public Utilities Commission.

Attachment C provides the O&M spending and the Off Cycle Risk Reduction removal counts by circuit, as well as the additional information noted in the paragraph above.

5. Inspection and Maintenance

I&M program costs for FY 2024 are shown in Attachment D. During this time, the Company identified one Level I deficiency. The Level I stray voltage deficiency was identified and repaired on August 3, 2023. When Level I deficiencies are identified, they are repaired immediately or within 30 days of the inspection.

The Company began its annual inspection of targeted overhead structures and elevated voltage testing on January 1, 2024 as inspections and elevated voltage testing now take place on a calendar year basis. The table below shows the number of units tested during this period.

Manual Elevated Voltage Testing				
Manual Elevated Voltage Testing	**Total System Units Requiring Testing**	**Units Completed 1/1/24 thru 3/31/24**	**Units with Voltage Found (>1.0v)**	**Percent of Units Tested with Voltage (>1.0v)**
Distribution Facilities	274,396	0	0	0.000%
Underground Facilities	12,438	0	0	0.000%
Street Lights and Signal Controls	4,929	0	0	0.000%

Attachment A

Capital Spending by Spending Rationale
For the Fiscal Year Ending March 31, 2024
($000)

Fiscal Year Ending March 31, 2024			
	Budget	**Actuals**	**Over Spend / (Under Spend)**
Customer Request/Public Requirement	$27,514	$35,307	$7,793
Damage Failure	15,192	20,811	5,618
Non-Discretionary Spending	***42,706***	***56,118***	***13,412***
Asset Condition	23,346	23,876	530
Non-Infrastructure	1,700	(1,083)	(2,783)
System Capacity & Performance	16,898	14,850	(2,048)
	41,944	*37,643*	*(4,301)*
Large Projects Separately Tracked	27,679	30,966	3,287
Discretionary Spending	***69,623***	***68,609***	***(1,014)***
Total Capital Spending	**$112,329**	**$124,727**	**$12,398**

Attachment B

Plant Additions by Spending Rationale
For the Fiscal Year Ending March 31, 2024
($000)

Fiscal Year Ending March 31, 2024			
	Target	**Actuals**	**% of Target Placed In Service**
Customer Request/Public Requirement	$27,742	$33,203	120%
Damage Failure	16,303	12,202	75%
Subtotal Non-Discretionary	*44,045*	*45,405*	*103%*
Asset Condition (w/Sep Tracked Large Projects)	32,720	38,806	119%
Non- Infrastructure	1,213	84	7%
System Cap & Perf (w/Sep Tracked Large Projects)	11,048	12,929	117%
Subtotal Discretionary	*44,981*	*51,819*	*115%*
Total Plant Additions	**$89,026**	**$97,224**	109%

Attachment C

Vegetation Management
For the Fiscal Year Ending March 31, 2024
($000)

Vegetation Management O&M Spending

Fiscal Year Ending March 31, 2024			
	Budget	**Actual Spending**	**% Spend**
Cycle Pruning (base)	$9,960	$9,313	94%
Off Cycle Risk Reduction	625	561	90%
Sub - T (on & off road)	540	150	28%
Police/Flagger Details	860	931	108%
Pockets of Poor Performance	120	17	14%
Risk Reduction - on cycle	290	534	184%
Core Crew (all other activities)	1,555	872	56%
Expenditures not categorized yet	0	1,408	--
Total O&M Spending	**$13,950**	**$13,785**	99%

Attachment C

Vegetation Management Span and Tree Tracker
For the Fiscal Year Ending March 31, 2024

FY24 Additional Work by Feeder						
Feeder	On Cycle Risk Reduction		On Cycle Extra clearance (Cycle trim spend)		SPANS TOTAL	TREES TOTAL
	Spans Worked	Trees Removed	Spans Worked	Trees Removed	995	**2524**
112W44	88	75		34	88	109
126W41	38	62			38	62
15F1			1		1	0
15F2			143	195	143	195
21F2				10	0	10
26W1	5	20			5	20
34F2			2	2	2	2
38F1	4	8			4	8
4F1			7		7	0
4F2			8		8	0
46F1	7	50	126	352	133	402
46F4				45	0	45
54F1	3	6	142	675.5	145	681.5
59F1		18		12	0	30
59F4	19	6			19	6
63F3			66	95	66	95
63F4			7	6.5	7	6.5
63F5			3	4	3	4
63F6			115	519	115	519
69F1			15	8	15	8
88F3			196	321	196	321
TOTAL	164	245	831	2279	995	2524

Attachment C

Vegetation Management Span and Tree Tracker
For the Fiscal Year Ending March 31, 2024

Total Off Cycle Hazard Trees removed by Feeder				TOTAL
Feeder	Trees Removed	Substation	District	**478**
127W41	4	Nasonville	Capital	
155F8	35	Chase Hill	Coastal	
23F4	22	Farnum Pike 23	Capital	
23F6	13	Farnum Pike	Capital	
26W1	24	Woonsocket 26	Capital	
26W3	8	Woonsocket	Capital	
34F1	106	Chopmist 34	Capital	
34F2	78	Chopmist	Capital	
34F3	34	Chopmist	Capital	
38F1	15	Putnam Pike 38	Capital	
38F5	10	Putnam Pike 38	Capital	
51F3	2	Bristol	Capital	
51F1	21	Bristol	Capital	
54F1	29	Coventry 54	Coastal	
59F1	1	Peacedale 59	Coastal	
63F3	7	Hopkins Hill 63	Coastal	
63F6	57	Hopkins Hill 63	Coastal	
68F1	43	Kenyon 68	Coastal	
68F4	8	Kenyon 68	Coastal	
TOTAL	478			

Off Cycle Ash Tree Removal Count FY24 (Sub-set of Total Off Cycle Hazard Trees Removed)				**TOTAL**
Feeder	Trees Removed	Substation	District	**407**
127W41	4	Nasonville	Capital	
155F8	35	Chase Hill	Coastal	
34F1	106	Chopmist	Capital	
34F2	78	Chopmist	Capital	
34F3	34	Chopmist	Capital	
38F1	14	Putnam Pike	Capital	
38F5	8	Putnam Pike	Capital	
45F2	28	West Greenville	Capital	
51F3	2	Bristol	Capital	
51F4	21	Bristol	Capital	
54F1	21	Coventry	Coastal	
63F3	1	Hopkins Hill	Coastal	
63F6	8	Hopkins Hill	Coastal	
68F1	43	Kenyon	Coastal	
68F4	4	Kenyon	Coastal	
TOTAL	407			

Attachment D

Inspection and Maintenance Program and Other O&M Spending
For the Fiscal Year Ending March 31, 2024
($000)

Fiscal Year Ending March 31, 2024			
	Budget	**Actuals**	**% Spend**
Opex Related to Capex	$400	$332	83%
Inspections & Repair Related Costs	338	654	193%
System Planning & Protection Coordination Study	25	0	0%
VVO/CRV Program	400	255	64%
Total O&M Spending	**$1,163**	**$1,241**	

Attachment E

Project Variance Report
For the Fiscal Year Ending March 31, 2024
($000)

	Fiscal Year Ending March 31, 2024			
Project Description	**Budget**	**Actuals**	**Over / (Under)**	**Variance Cause**
Dyer Street Substation (at South Street)	$0	$2,725	$2,725	See Attachment G for additional details.
East Providence Substation	$1,330	$906	($424)	See Attachment G for additional details.
Warren Substation	$1,969	$2,518	$549	See Attachment G for additional details.
Franklin Sq Breaker Replacement	$437	$1,362	$925	Work carried over from previous year.
Weaver Hill Road Substation	$1,507	$593	($914)	Delays and deferred to FY 2025.
Nasonville Substation	$1,912	$2,585	$673	Over budget due to allocation of area study costs/PS&I reclassification.
Nasonville Damage/Failure Project	$1,092	$4,198	$3,106	Civil construction bids higher than originally estimated, UG D Line scope and design changes required.
3763 Pole Replacements	$783	$1,565	$782	Deferred from FY 2023.
	$9,030	**$16,454**	**$7,423**	

Attachment F

Damage/Failure Detail by Work Type
For the Fiscal Year Ending March 31, 2024
($000)

Fiscal Year Ending March 31, 2024						
Description	**D Line Blanket**	**Property Damage**	**D Sub Blanket**	**Specifics**	**Storms**	**Total**
Apponaug Transformer Fail	$0	$0	$119	$0	$0	$119
Hopkins Hill Transformer Failure	0	0	0	185	0	185
Monthly Confirming Work	6,681	0	0	0	0	6,681
Nasonville Failure	0	0	0	4,198	0	4,198
OH Electric Distribution	2,382	0	0	0	0	2,382
Other	30	0	214	(5)	0	240
Property Damage	0	1,021	0	0	0	1,021
Sprague St Transformer Fail	0	0	364	0	0	364
Storms	0	0	0	0	4,784	4,784
Streetlighting	17	0	0	0	0	17
UG Electric Distribution	805	0	0	0	0	805
Westerly Spare Transfomers	0	0	0	15	0	15
Total	**$9,915**	**$1,021**	**$698**	**$4,394**	**$4,784**	**$20,811**

Please see the Excel file attached to this quarterly report with additional details on Damage/Failure capital spending.

Attachment G

Separately Tracked Large Projects
For the Fiscal Year Ending March 31, 2024

Southeast Substation
Predates Existing Area Study Process
Current Status – Design and Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2024 Actuals	Total Project Cost Forecast	2024 Budget	Total Project Cost Forecast
Southeast Substation Project	**$412**	**$24,170**	**$66**	**$23,703**

Capital spending totaled $0.4 million during FY 2024. The Dunnell Park substation portion of this project is complete. The majority of the assets associated with the distribution line project are in service. Building demolition was pushed from January 2024 due to material delays. The engineering for the Pawtucket #1 Substation project is complete and building demolition will begin during the Summer of 2024.

The Southeast Substation project, excluding the related distribution line projects, will continue to be shown on Attachment G as a "Separately Tracked Major Project" in FY 2025 and will be outside the "soft budget cap".

Dyer Street Substation at South Street
Predates Existing Area Study Process
Current Status – Design and Execute

($ 000's)	**Actuals & Current Forecast**		**ISR Plan Budget**	
	FY 2024 Actuals	**Total Project Cost Forecast**	**2024 Budget**	**Total Project Cost Forecast**
Dyer Street Substation Project	**$2,725**	**$24,281**	**$0**	**$21,641**

Capital spending totaled $2.7 million in FY 2024. The distribution line portion of the project was placed into service in February 2024. Building demolition of the existing Dyer Street Substation is expected to begin during the Summer of 2024 pending receipt of final permits.

The total project cost forecast increased due to:

- Supply chain delays adding a year to the project schedule.
- Scope increases due to underground obstructions and a collapsed duct bank.

The Dyer Street Substation project, excluding the Distribution Line project, will continue to be shown on Attachment G as a “Separately Tracked Major Project” in FY 2025 and will be outside the “soft budget cap”.

Providence Study – Phase 1B, 2 & 4
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Final Engineering/Design and Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2024 Actuals	Total Project Cost Forecast	2024 Budget	Total Project Cost Forecast
Total Providence Study	**$24,204**	**$90,775**	**$24,314**	**$90,753**

The Company is now reporting all the Providence Study work as one project as all components are being managed collectively. Please note, the Admiral Street Substation project, excluding the related distribution line projects, will continue to be shown on Attachment G as a “Separately Tracked Major Project” in FY 2025 and will be outside the “soft budget cap”.

The Providence Study Phase 2 – Geneva, Olneyville, Rochambeau 4 KV Conversion project involves converting and retiring the 4.16kV load from the Geneva, Olneyville, and Rochambeau Avenue substations for 12.47kV operation. This project was budgeted to begin construction in FY 2024, but resources were shifted to complete the line portion of the Knightsville project to accommodate the City’s request. Civil work on the substation portion of Knightsville began.

East Providence Substation
East Bay Area Study (August 2015)
Current Status – Design & Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2024 Actuals	Total Project Cost Forecast	2024 Budget	Total Project Cost Forecast
East Providence Substation	**$906**	**$22,119**	**$1,330**	**$17,555**

During FY 2024, capital spending totaled $0.9 million. Final engineering and procurement occurred. An updated study grade estimate of $22.1 million was issued at the end of March 2024. This included an updated in-service date (2027 versus 2022), inflation, and bids received on the transformer and other similar metal-clad switchgears. The construction grade estimate for the substation will be complete in June 2025. The driver for the FY 2024 underspend was due to revisions made to project execution plan caused by the approximately one year increase in substation transformer lead time. Distribution line work was walked out of FY 2024 and offset by the Warren Substation distribution line work walked into FY 2024.

The East Providence Substation project, excluding the related distribution line projects, will continue to be shown on Attachment G as a “Separately Tracked Major Project” in FY 2025 and will be outside the “soft budget cap”.

Warren Substation
East Bay Area Study (August 2015)
Current Status – Design & Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2024 Actuals	Total Project Cost Forecast	2024 Budget	Total Project Cost Forecast
Warren Substation	**$2,518**	**$10,171**	**$1,969**	**$10,171**

During FY 2024, capital spending was $2.5 million for both distribution line and substation work against a budget of $2.0 million. Distribution line work is ongoing. Engineering and procurement are ongoing for the substation and construction will begin in January 2026. The driver for the FY 2024 overspend was due to revisions made to project execution plans. Warren Substation's distribution line work was walked into the FY 2024 Plan and offset by the East Providence Substation's line work which was walked out of the FY 2024 Plan.

The Warren Substation project will no longer be shown on Attachment G as a "Separately Tracked Major Project" in FY 2025 and will be included in the "soft budget cap". However, the Company anticipates that when the substation portion of the project is re-estimated, it may exceed the $5 million threshold.

Tiverton
Tiverton Area Study 33F6

In the Tiverton area, the DG application for the installation of a new feeder, 33F6, has been approved and the project is progressing. This generation site went into service in late 2023. The Tiverton Area Study (September 2021) identified the need to extend the proposed 33F6 circuit to the south for thermal (capacity) limits, contingency response capability, and voltage issues. The Study included a cash flow showing the circuit extension to be in-service in 2028. The Company filed a Petition for Acceleration Due to Distributed Generation Project under Docket 23-37 EL.

This project is not considered a "Separately Tracked Major Project" in FY 2025 and will not be in Attachment G of future ISR Plan quarterly reports.

Attachment H

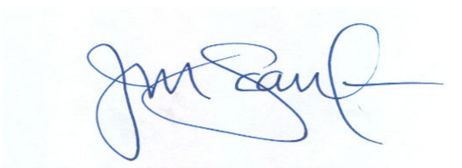
Meter Purchases
For the Fiscal Year Ending March 31, 2024

Quantity of Meters Purchased		
Type	**Description**	**Quantity**
METER	CENTRON - 2S 240V CL200	20,700
METER	CENTRON - 16S CL320	360
INSTRUMENT TRANSFORMER	CUR OUTDOOR 70/1 8.4KV	17
INSTRUMENT TRANSFORMER	CUR OUTDOOR 175/1	7
INSTRUMENT TRANSFORMER	CUR OUTDOOR 300/1	4
INSTRUMENT TRANSFORMER	CUR OUTDOOR 15KV	10
INSTRUMENT TRANSFORMER	CUR OUTDOOR 5/5 15KV	11
INSTRUMENT TRANSFORMER	CUR OUTDOOR 50/5 15KV	9
INSTRUMENT TRANSFORMER	CUR OUTDOOR 75/5 15KV	30
INSTRUMENT TRANSFORMER	CUR OUTDOOR 100/5 15KV	12
INSTRUMENT TRANSFORMER	CUR OUTDOOR 300/5 15KV	12
INSTRUMENT TRANSFORMER	200:5 BASE BUSHINGS	10
INSTRUMENT TRANSFORMER	300:5 BASE BUSHINGS	64
INSTRUMENT TRANSFORMER	400:5 BASE BUSHINGS	240
INSTRUMENT TRANSFORMER	1200:5 BASE BUSHINGS	90
INSTRUMENT TRANSFORMER	2000:5 BASE BUSHINGS	48
INSTRUMENT TRANSFORMER	3000:5 BASE BUSHINGS	48
INSTRUMENT TRANSFORMER	200:5 CAP	210
	TOTAL	**21,882**

Certificate of Service

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

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



Joanne M. Scanlon

May 15, 2024
Date

Docket No. 22-53-EL – RI Energy's Electric ISR Plan FY 2024
Service List as of 4/6/2023

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. 280 Melrose St. Providence, RI 02907 Adam S. Ramos, Esq. **Hinckley Allen** 100 Westminster Street, Suite 1500 Providence, RI 02903-2319 Stephanie Briggs Patricia C. Easterly Susan M. Toronto Alan LaBarre Ryan Constable Kathy Castro Jeffrey Oliveira	amarcaccio@pplweb.com; cobrien@pplweb.com; jscanlon@pplweb.com; aramos@hinckleyallen.com; sbriggs@pplweb.com; NABegnal@RIEnergy.com; smtoronto@RIEnergy.com; ATLaBarre@RIEnergy.com; rconstable@RIEnergy.com; krcastro@RIEnergy.com; CJRooney@RIEnergy.com; joliveira@pplweb.com; wanda.reder@gridxpartners.com;	401-784-4263
Division of Public Utilities (Division) Gregory Schultz, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	gSchultz@riag.ri.gov; Ellen.golde@dpuc.ri.gov; John.bell@dpuc.ri.gov; Al.contente@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov; Jon.Hagopian@dpuc.ri.gov; Margaret.l.hogan@dpuc.ri.gov; Paul.roberti@dpuc.ri.gov;	

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Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources Al Vitali, Esq.	Albert.vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Shauna.Beland@energy.ri.gov; William.Owen@energy.ri.gov; Matthew.Moretta.CTR@energy.ri.gov;	
Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mbedell@riag.ri.gov;	401-274-4400 x 2297
File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Esq. Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Emma.rodvien@puc.ri.gov;	401-780-2107
Matt Sullivan, Green Development LLC	ms@green-ri.com;	

Attachment 2

2023 Electric Service Quality Report

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

280 Melrose Street
Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

May 1, 2024

VIA ELECTRONIC MAIL

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

RE: Docket 3628 – 2023 Service Quality Report (Electric Operations)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), enclosed, please find an electronic version of the Company's Annual Service Quality Report which assesses the quality of the Company's electric operations for the performance period of January 1, 2023 through December 31, 2023 (the "2023 Service Quality Report" or "Report"). As indicated in the Report, the Company's performance for both reliability and customer service was within acceptable regulatory levels and, as a result, the Company did not incur a penalty.

The 2023 Service Quality Report stems from the Company's electric Service Quality Plan (the "SQ Plan") as approved by the Public Utilities Commission (the "PUC" or "Commission") through Order Nos. 18294, 19020, and 22456.[1] The purpose of the SQ Plan is to ensure that customers receive a reasonable level of service. To this end, the SQ Plan establishes performance standards for service reliability, which includes the categories of interruption frequency and interruption duration, and for customer service, which includes the categories of customer contact and telephone calls answered. For each category, a benchmark or range representing a regulatory acceptable performance is set forth. If the Company's performance falls below the acceptable range in any of the four categories, a penalty is assessed. The Company cannot earn a monetary award for exceeding expectations; however, it can accrue offsets for good performance in one category which may be used to offset a penalty incurred in the other categories. For additional details on the SQ Plan, please see Attachment 1 of the Settlement Agreement.[2]

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[1] Through Order No. 18294, the PUC approved a Settlement Agreement between the Company and the Division of Public Utilities and Carriers (Division) which incorporated the SQ Plan to be effective January 1, 2005 (the Settlement Agreement). The SQ Plan also includes amendments made in 2007 (Order No. 19020) and 2016 (Order No. 22456).

[2] See http://www.ripuc.ri.gov/eventsactions/docket/3628-NEC-Ord18294(7-12-05).pdf

For 2023, the Company did not incur a penalty. Specifically, the Company's performance fell within an acceptable regulatory range for each of the four categories, meaning there were no penalties assessed. For a summary of the results, please see Section 2 of the Report.

In addition, the Report: (1) References quarterly reports filed by the Company that detail the worst performing circuits; (2) References monthly reports filed by the Company that detail trouble/non-outages; (3) Calculates the Company's annual meter reading performance; and (4) Identifies Major Event Days. In accordance with the SQ Plan, Major Event Days are not factored into the Company's performance under this Report and are separately analyzed and reported. For additional details on these items, please see Section 3 of the Report.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 3628 Service List

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

2023 Service Quality Report

May 1, 2024

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 3628

Submitted by:

Rhode Island Energy™
a PPL company

TABLE OF CONTENTS

SECTION 1: RELIABILITY AND CUSTOMER SERVICE PERFORMANCE STANDARDS

Interruption Frequency and Duration

Under the Service Quality Plan, an interruption is defined as the loss of electric service to more than one customer for more than one minute. The interruption duration is defined as the period of time, measured in minutes, from the initial notification of the interruption event to the time when service has been restored to the customers. Interruptions are tracked using System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). SAIFI is calculated by dividing the total number of customers interrupted by the total number of customers served. SAIFI measures the number of times per year the average customer experienced an interruption. This is an average, so in any given year some customers will experience no interruptions, and some will experience several interruptions. SAIDI measures the length of interruption time that the average customer experienced for the year. It is calculated by dividing the total customer minutes of interruption by the total number of customers served. Certain events are defined as Major Event Days and are excluded from the calculation of reliability performance standards for penalty and offset assessment. There was one Major Event Day that occurred during 2023. The Major Event Day was December 18.

2023 Total Frequency Standard		2023 Frequency (SAIFI) Results	
Frequency of Interruptions per Customer	(Penalty)/Offset	Frequency of Interruptions per Customer	Annual (Penalty)/Offset
Greater than 1.18	($916,000)		
1.06-1.18	linear interpolation		
0.84-1.05	$0		
0.75-0.83	linear interpolation	0.769	$180,656
Less than 0.75	$229,000		

2023 Duration (SAIDI) Standard		2023 Duration (SAIDI) Results	
Duration of Interruptions (minutes)	(Penalty)/Offset	Duration of Interruptions (minutes)	Annual (Penalty)/Offset
Greater than 89.9	($916,000)		
72.0-89.9	linear interpolation		
45.9-71.9	$0	52.62	$0
36.7-45.8	linear interpolation		
Less than 36.7	$229,000		

CUSTOMER SERVICE PERFORMANCE STANDARDS

Customer Contact Survey

The customer contact survey results are based on responses from Rhode Island Energy electric customers from a survey performed by an independent third-party consultant, Praxis Research Partners. Praxis surveys a random sample of customers who have contacted Rhode Island Energy recently to determine their level of satisfaction with their most recent contact with the Company regarding any call reason. Survey results are based on a composite measure of two questions from Rhode Island Energy's internal contactor survey: (1) Overall, on a scale from 1 to 10, where 1 means "dissatisfied", and 10 means "satisfied", how satisfied are you with the services provided by Rhode Island Energy? (2) Overall, on a scale from 1 to 10, where 1 means "dissatisfied", and 10 means "satisfied", how satisfied are you with the quality of service provided by the telephone representative? The individual score for each question is the percentage of respondents who provided a rating of "8", "9", or "10" on a 10-point scale, where 1 means "dissatisfied", and 10 means "satisfied". The "percent satisfied" composite score is a simple arithmetic average of the satisfaction score from each question.

2023 Customer Contact Standard		2023 Customer Contact Results	
Percent Satisfied	(Penalty)/Offset	Percent Satisfied	Annual (Penalty)/Offset
Less than 74.4%	($184,000)		
74.4%-78.7%	linear interpolation		
78.8%-87.6%	$0	81%	$0
87.7%-92.0%	linear interpolation		
More than 92.0%	$46,000		

Telephone Calls Answered Within 20 Seconds

The calls answered performance standard reflects the annual percentage of calls answered within 20 seconds, specifically for electric customers. "Calls answered" include calls answered by a customer service representative (CSR) and calls completed within the Voice Response Unit (VRU). The time to answer is measured once the customer selects to either speak with a CSR or use the VRU.

2023 Calls Answered Standard		2023 Calls Answered Results	
% Answered Within 20 Seconds	(Penalty)/Offset	% Answered Within 20 Seconds	Annual (Penalty)/Offset
Less than 53.5%	($184,000)		
53.5% - 65.7%	linear interpolation		
65.8% - 90.4%	$0	85.44%	$0
90.5% - 100.0%	linear interpolation, to maximum of $46,000		

SECTION 2: CALCULATION OF PENALTY/OFFSET

Rhode Island Energy
2023 Results of Service Quality Plan
Calculation of Penalty/Offset

Performance Standard	Potential Penalty (a)	Potential Offset (b)	2023 Results (c)	Maximum Penalty (d)	One Std Dev. Worse Than Mean (e)	Mean (f)	One Std Dev. Better Than Mean (g)	Maximum Offset (h)	Annual (Penalty)/ Offset (i)
Reliability - Frequency	$ 916,000	$229,000	0.77	1.18	1.05	0.94	0.84	0.75	$180,656
Reliability - Duration	$ 916,000	$229,000	52.6	89.9	71.9	57.5	45.9	36.7	$0
Customer Service - Customer Contact Survey	$ 184,000	$ 46,000	81.0%	74.4%	78.8%	83.2%	87.6%	92.0%	$0
Customer Service - Telephone Calls Answered	$ 184,000	$ 46,000	85.4%	53.5%	65.8%	78.1%	90.4%	100.0%	$0
Total Penalty/Offset	$2,200,000	$550,000							$180,656

Notes:

Columns (a), (b), and (d)-(h) are per the Amended Electric Service Quality Plan, RIPUC Docket No. 3628.

Column (c) represents the actual 2023 annual results for the performance standards listed in the first column.

Column (i) is calculated as follows:

- For Reliability Standards:

If Column (c) is between Column (g) and Column (e):	$0
If Column (c) is between Column (h) and Column (g):	[Column (g) - Column (c)] ÷ [Column (g) - Column (h)] x Column (b)
If Column (c) is between Column (e) and Column (d):	[Column (c) - Column (e)] ÷ [Column (d) - Column (e)] x Column (a)
If Column (c) is greater than Column (d):	100% of Column (a)
If Column (c) is less than Column (h):	100% of Column (b)

- For Customer Service Standards:

If Column (c) is between Column (e) and Column (g):	$0
If Column (c) is between Column (g) and Column (h):	[Column (c) - Column (g)] ÷ [Column (e) - Column (d)] x Column (b)
If Column (c) is between Column (d) and Column (e):	[Column (e) - Column (c)] ÷ [Column (e) - Column (d)] x Column (a)
If Column (c) is less than Column (d):	100% of Column (a)
If Column (c) is greater than Column (h):	100% of Column (b)

SECTION 3: ADDITIONAL REPORTING CRITERIA

Under the Company's Service Quality Plan, the following additional reporting criteria are required to be filed with the PUC.

1. **Reporting Requirement:** Each quarter, the Company will file a report of 5% of all circuits designated as worst performing on the basis of customer frequency.

   Included in the report will be:
   1. The circuit ID and location.
   2. The number of customers served.
   3. The towns served.
   4. The number of events.
   5. The average duration.
   6. The total customer minutes.
   7. A discussion of the cause or causes of events.
   8. A discussion of the action plan for improvements including timing.

   Results: The Company filed its first quarter 2023 feeder ranking results on May 10, 2023, the second quarter results on October 25, 2023, the third quarter results on November 15, 2023, and fourth quarter results on March 26, 2024.

2. **Reporting Requirement:** The Company will track and report monthly the number of calls it receives in the category of Trouble, Non-Outage. This includes inquiries about dim lights, low voltage, half-power, flickering lights, reduced TV picture size, high voltage, frequently burned-out bulbs, motor running problems, damaged appliances and equipment, computer operation problems, and other non-interruptions related inquiries.

   Results: The Company filed the required Trouble, Non-Outage reports during 2023, with the final report for the 13 months ended December 2023 filed on January 24, 2024.

3. **Reporting Requirement:** The Company will report its annual meter reading performance as an average of monthly percentage of meters read.

   Results: During 2023, the Company's annual meter reading performance (as an average of monthly percentage of meters read) was 98.98% compared to 98.88% in 2022, and 98.60% during 2021. The following table details the percentage of meters read per month for 2023, 2022 and 2021.

Monthly Percentage of Meters Read

	2023	2022	2021
January	98.92%	98.71%	98.59%
February	98.96%	98.71%	98.53%

	2023	2022	2021
March	98.93%	98.75%	98.63%
April	98.98%	98.90%	98.70%
May	99.04%	98.96%	98.70%
June	99.03%	98.95%	98.75%
July	99.00%	98.95%	98.66%
August	99.05%	99.12%	98.36%
September	99.03%	98.96%	98.83%
October	99.13%	98.76%	98.57%
November	99.14%	98.95%	98.18%
December	98.49%	98.87%	98.69%
YTD Average	98.98%	98.88%	98.60%

4. **Reporting Requirement:** For each event defined as a Major Event Day, the Company will prepare a report, which will be filed annually as part of the annual Service Quality filing, detailing the following information:

1. Start date/Time of event
2. Number/Location of crews on duty (both internal and external crews)
3. Number of crews assigned to restoration efforts
4. The first instance of mutual aid coordination
5. First contact with material suppliers
6. Inventory levels: pre-event/daily/post-event
7. Date/Time of request for external crews
8. Date/Time of external crew assignment
9. # of customers out of service by hour
10. Impacted area
11. Cause
12. Weather impact on restoration
13. Analysis of protective device operation
14. Summary of customers impacted

Results: IEEE Std. 1366-2012[1] identifies reliability performance during both day-to-day operations and Major Event Days. Major Event Days represent those few days during the year on which the energy delivery system experienced stresses beyond that normally expected, such as severe weather. A day is considered a Major Event Day if the daily SAIDI exceeds a threshold value, calculated using the IEEE methodology. For 2023 the TMED value was 6.27 minutes of SAIDI (using IEEE Std. 1366-2012 methodology). There was one major storm day that exceeded this threshold in 2023. The storm occurred on December 18. The storm details are described below.

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[1] RIPUC Order No 19020 refers to IEEE Std. 1366-2003. This standard has been superseded by IEEE Std. 1366-2012. The updated standard requires no changes for identifying Major Event Days or calculating thresholds.

December 18, 2023 Storm

1. **Start date/Time of event:**

   The storm began on December 18, with scattered interruptions starting at 5:00 a.m. in the early morning of December 18. The peak was around 11:06 a.m. on December 18. The peak reached 27,998 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**

   The Company secured a total of approximately 450 internal and external field crews to restore power to customers in Rhode Island, consisting of 222 external crews and 224 internal crews. The internal and external field crew numbers included transmission and distribution overhead line, forestry, substation, underground, wires down, and damage assessment personnel.

3. **Number of crews assigned to restoration efforts:**

   At peak, the Company had the following crews performing restoration activities throughout the impacted areas in the State.

   Crew Type
   Internal Overhead Line - 35 crews
   External Overhead Line - 99 crews
   Internal Trouble Worker – 36 crews
   Internal Wire Down - 54 crews
   Internal Underground - 8 crews
   Internal Substation - 20 crews
   Contractor Forestry - 156 crews

4. **The first instance of mutual aid coordination:**

   The Incident Commander for Rhode Island Energy did not request mutual assistance from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event.

5. **First contact with material suppliers:**

   The first contact with material suppliers was on December 17.

6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1107	1108	1115	1120	1101 Alloc.
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGSTOWN	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC
12/18/2023	-	$1,198,256	-	$230,034	-

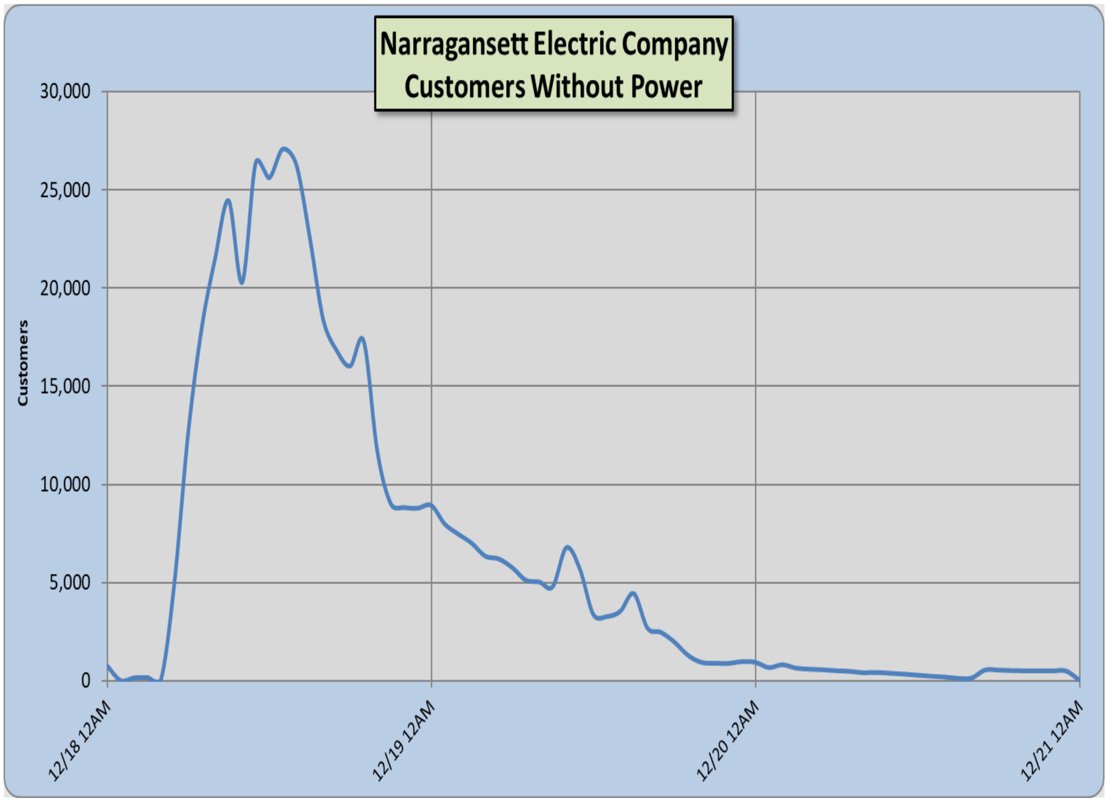
7. **Date/Time of request for external crews:**

Given the potential magnitude of the storm and forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all its regional preparation for the storm, consistent with its Emergency Response Plan. The first request for external contractor crews was at 10:00 a.m. on December 18.

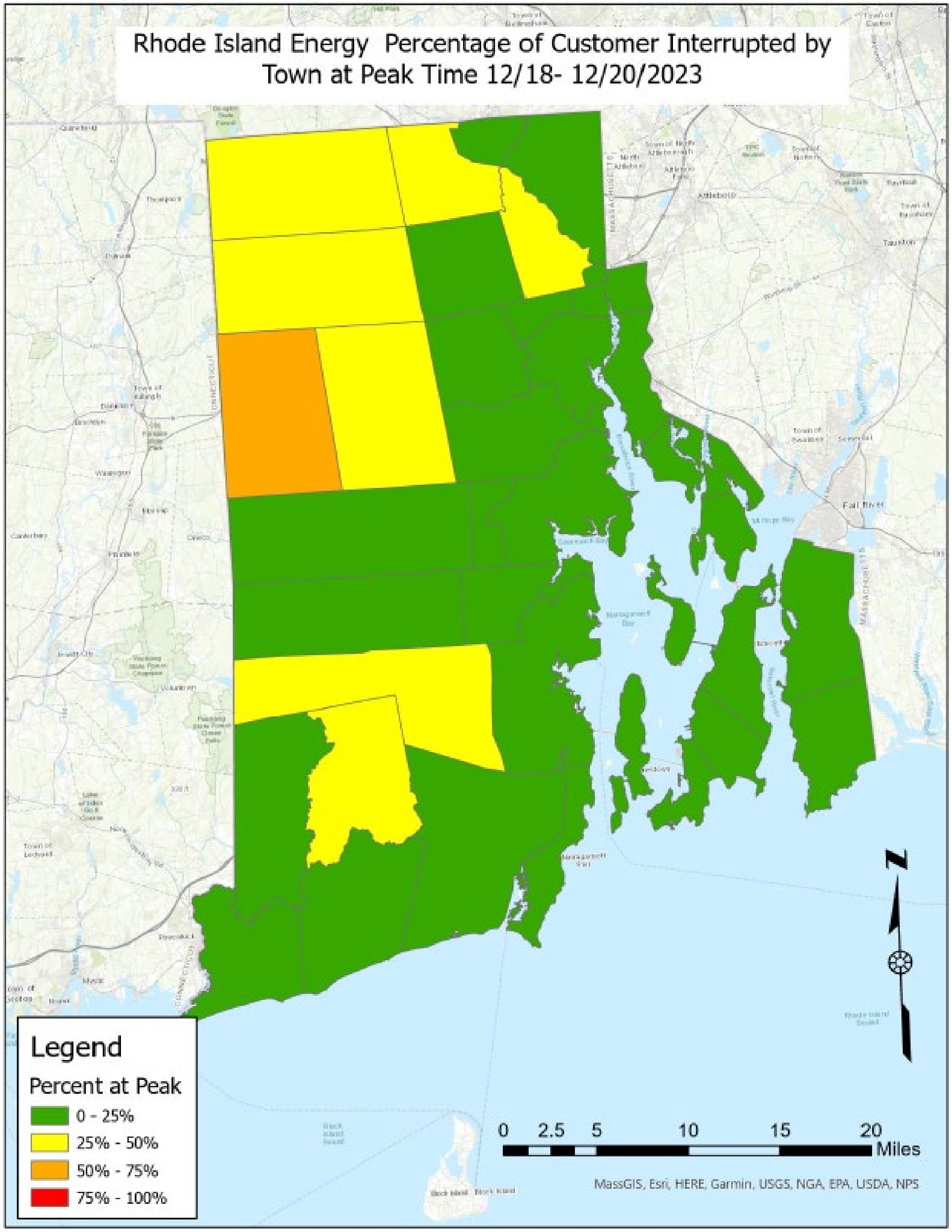
8. **Date/Time of external crew assignment:**

External crews were assigned to work around 10:00 am on December 18.

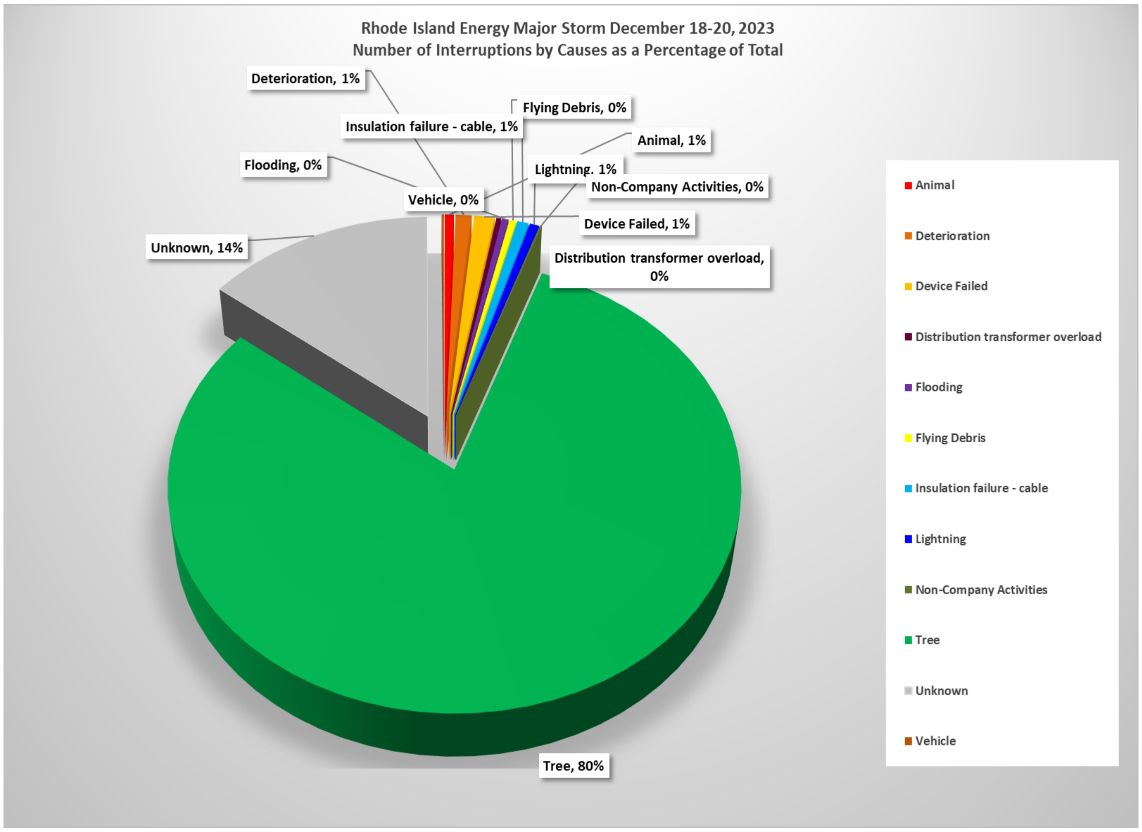
9. # of customers out of service by hour:



10. Impacted area:



11. Cause:



12. Weather impact on restoration:

The storm was a long duration weather event that resulted in moderate damage to the Company's electrical system. The Storm brought heavy rain and strong wind gusts to the state. Peak wind gusts were generally in the 55-65 mph range, with Providence experiencing a peak gust of 62 mph, with 1.6 inches of rain accumulated. The Towns of Foster and Glocester were affected most heavily with 100 percent of customers impacted by the event.

13. Analysis of protective device operation:

Rhode Island Energy maintains a wide array of protection and interrupting devices designed to separate faulted components from the electrical system while containing outages to the smallest area practicable. On the distribution system, those devices include fuse cutouts, reclosers, and circuit breakers of various designs. On the transmission system, interrupting devices include circuit breakers, air-break switches, and circuit switchers. Protection relays are used to detect the faults and operate the interrupting device(s) to isolate a faulted component(s).

For the distribution system, design standards exist that indicate how protection devices are to be deployed and coordinated with other devices. Distribution engineers evaluate such devices under normal and fault conditions. Where recent performance may indicate a need for improvement, Rhode Island Energy performs engineering studies and makes improvements. During a major storm like this event, outages in the distribution system may be far too extensive to assess the function and coordination of individual protection devices in detail, as the focus of storm response is on service restoration. A meaningful analysis would be difficult to perform unless there were specific indications of protection equipment mis-operation.

Protection standards, guides and practices also exist and are followed in the design of Rhode Island Energy's transmission system. Post-event analysis of all interruptions in the Rhode Island Energy Bulk Electric System (BES) is performed to confirm proper operation of protection systems. If an improper operation is identified, further analysis is conducted to identify the cause and to propose and implement a solution. In addition, Rhode Island Energy undertakes analysis of transmission and substation protection devices and coordination where there is evidence of mis-operation.

14. Summary of customers impacted:

December 18, 2023

On December 18, Rhode Island experienced 436 interruptions that affected 56,177 customers and 2,5619,476 customer minutes of interruption. On average these interruptions resulted in 0.11 SAIFI, 50.41 minutes of SAIDI. Since a SAIDI value of 50.41 minutes exceeded the threshold value of 6.27 minutes, December 18 is qualified as a Major Event Day under the IEEE methodology.

December 19, 2023

On December 19, Rhode Island experienced 18 interruptions that affected 5,063 customers and 482,284 customer minutes of interruption. On average these interruptions resulted in 0.01 SAIFI, 0.95 minutes of SAIDI. Since a SAIDI value of 0.95 minutes did not exceed the threshold value of 6.27 minutes, December 19 is not qualified as a Major Event Day under the IEEE methodology.

December 20, 2023

On December 20, the restoration was still ongoing, but the daily SAIDI value was very small and less than the threshold value of 6.27 minutes. December 20 is not qualified as a Major Event Day under the IEEE methodology.

Certificate of Service

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

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

Joanne M. Scanlon

May 1, 2024
Date

Rhode Island Energy – Electric Service Quality Plan – Docket 3628 Service List Updated 5/1/2024

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Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mbedell@riag.ri.gov;	401-274-4400 x 2297
George Wiley Center Jennifer L. Wood Executive Director R.I. Center for Justice 1 Empire Plaza, Suite 410 Providence, RI 02903	jwood@centerforjustice.org;	401-491-1101
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Boulevard Warwick, RI 02888	Luly.massaro@puc.ri.gov; Todd.bianco@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107

PRE-FILED DIRECT TESTIMONY

OF

JEFFREY D. OLIVEIRA

August 1, 2024

Table of Contents

I. Introduction

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. By whom are you employed and in what position?

A. I am employed by the PPL Services Corporation as a Lead Rates and Regulatory Specialist. My current duties include leading the revenue requirement analyses and modeling that support regulatory filings, regulatory strategies, and rate cases for The Narragansett Electric Company d/b/a Rhode Island Energy (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 the National Grid USA Service Company, Inc. (the "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 operations of Southern Union d/b/a New England Gas Company at which time I joined the Service Company as a Senior Accounting Analyst. In January 2009, I became a Senior Revenue Requirement

Analyst in the 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 Service Company. 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"). Upon closing of the Acquisition, I began working in my current position.

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

A. Yes. I filed pre-filed joint direct testimony with the PUC in support of the Company's 2024 Electric Pension Adjustment Factor Filing in Docket No. 24-16-EL and have testified before the PUC in support of the Company's filings in proceedings as follows: 2023 Electric Pension Adjustment Factor Filing in Docket No. 23-27-EL; 2023 Distribution Adjustment Charge Filing, Docket No. 23-23-NG; Fiscal Year ("FY") 2023 Gas Infrastructure, Safety, and Reliability Plan Reconciliation Filing, Docket No. 5210; FY2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing, Docket No. 5209; 2023 Renewable Energy Growth Factor Filing, Docket No. 22-04-REG; 2023 Annual Retail Rate Filing, Docket No. 23-03-EL; FY2024 Gas Infrastructure, Safety, and Reliability Plan, Docket No. 22-54-NG; FY2024 Electric Infrastructure, Safety, and Reliability Plan, Docket No. 22-53-EL;

2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG; 2022 Pension Adjustment Factor Filing, Docket No. 22-19-EL; 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 No. 5234; Joint Petition of the Company 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.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric Infrastructure, Safety, and Reliability ("ISR") factor, for effect on April 1, 2023. That factor was based on a projected FY 2024 Electric ISR revenue requirement of $55,418,057 for the estimated operation and maintenance ("O&M") work associated with the Company's vegetation management ("VM") and inspection and maintenance ("I&M") programs for the Company's FY ended March 31, 2024, on the estimated ISR plant additions during the Company's FYs ended March 31, 2024 and 2023, and on the actual ISR additions during the Company's Fiscal Years ended March 31, 2018, 2019, 2020, 2021, and 2022 which were incremental to the levels reflected in rate base in the Company's last base rate case (Docket No. 4770). On September 1, 2018, new distribution base rates as approved in Docket No. 4770 became effective. The revenue requirements on actual ISR additions made from FY 2012 through FY 2017 plus forecasted ISR additions for FY 2018, FY 2019, and a portion of FY 2020 were included in these new base rates. Thus, the purpose of my testimony is to present an updated FY 2024 Electric ISR revenue requirement associated with actual FY 2024 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2024 incremental to the level of investment assumed in Docket No. 4770, and actual tax deductibility percentages, tax gains and losses on retirements and net operating loss ("NOL") utilization for FY 2023, an adjustment for the review of distributed generation ("DG") projects that the Company undertook, and a hold harmless adjustment credit.

The updated FY 2024 revenue requirement also includes an adjustment associated with the property tax recovery formula that was approved in Docket No. 4323 and Docket No. 4770. As the vintage years FY 2012 through FY 2017 were rolled into the base rates approved in Docket No. 4770 that became effective on September 1, 2018, the property tax recovery adjustment covers only the months of September 2018 through March 31, 2024.

As shown on Attachment JDO-1, Page 1, at Line 21, the updated FY 2024 ISR revenue requirement collectible through the Company's Electric ISR factor for the FY 2024 period, including updated tax deductibility adjustments to the FY 2023 revenue requirement, totals $54,282,082. This is a decrease of $1,135,976 from the projected FY 2024 Electric ISR revenue requirement of $55,418,057, previously approved by the PUC in this docket. This decrease is primarily attributable to (1) a net decrease in the FY 2023 and FY 2024 revenue requirement on a lower level of capital investment; (2) a net decrease to the FY 2018 through FY 2023 revenue requirements for the results of the DG project review as described in the testimony of Ms. Gooding; and (3) a decrease for the tax updates for FY 2023 taxes as described in the testimony of Ms. Hawk. These decreases were partially offset by (1) an increase in the actual effective FY 2024 property tax rate compared with the projected effective FY 2024 property tax rate in the FY 2024 ISR Plan, and (2) an increase to the revenue requirement for the updated FY 2023 and FY 2024 hold harmless adjustments as discussed in the testimony of Ms. Hawk.

Q. Does the updated FY 2024 revenue requirement in this filing include an impact of the updated FY 2023 NOL utilization?

A. Yes. The cumulative impact of the updated FY 2023 NOL utilization on the FY 2024 revenue requirement is addressed in the prefiled testimony of Ms. Hawk, as shown on JDO-1, Page 26, Line 11.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following attachment:

- Attachment JDO-1 Revenue Requirement Summary and Calculation FY 2024 Electric Infrastructure, Safety, and Reliability Plan Reconciliation

II. Electric ISR FY2024 Revenue Requirement

Q. Did the Company calculate the updated FY 2024 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2023 ISR factor reconciliation?

A. Yes, the Company calculated the updated FY 2024 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions. Similar to the FY 2023 filing, the calculation incorporates the approved weighted average cost of capital and depreciation rates from Docket No. 4770 and known tax deductibility percentages, tax gains and losses on retirements and NOL utilization for FY 2023.

The updated FY 2024 ISR revenue requirement presented in this reconciliation is nearly identical to the calculated revenue requirement used to develop the approved ISR factors that became effective April 1, 2023. A detailed description of the revenue requirement calculation employed can be found in the revenue requirement testimony included in the Company's FY 2024 ISR Plan Proposal filing in this docket. For brevity, I limit this testimony to the following: (1) a description of the impact of Docket No. 4770 to the Electric ISR revenue requirement, (2) a summary of the revenue requirement update shown on Page 1 of Attachment JDO-1; and 3) a summary of the adjustment related to the DG review.

Q. Please summarize the change in the FY 2024 ISR revenue requirement proposed in this reconciliation filing as compared to the FY 2024 revenue requirement effective April 1, 2023, which was based on projected capital additions approved in the FY 2023 and FY 2024 ISR Plans.

A. As shown in Attachment JDO-1, Page 1, Line 21, column (c), the overall FY 2024 revenue requirement decrease is $1,135,976, which is the net impact of: (1) a $3.0 million decrease in the FY 2024 revenue requirement on vintage FY 2023 ISR capital additions mainly driven by the actual FY 2023 capital additions compared to forecasted FY 2023 additions and the reflection of the DG project review adjustment that was made in the FY 2023 ISR revenue requirement reconciliation, in addition to the FY 2023 income tax deductibility update; (2) a $0.5 million increase in the FY 2024 revenue requirement on vintage FY 2024 ISR capital additions mainly caused by $8.3 million higher capital investment placed into service compared to the amount approved in the FY 2024 Plan; (3) a $2.4 million increase in the FY 2024 property tax recovery adjustment mainly driven by the higher actual tax rate in FY 2024 compared to the previous filed FY 2024 Plan; (4) a decrease of $0.9 million due to the true-up of FY 2023 revenue requirement to reflect actual tax deductibility as described in Ms. Hawk's testimony; (5) a decrease of $0.7 million for the FY 2024 income tax deductibility update from the FY 2024 Plan; (6) a net reduction to the FY 2024 revenue requirement of $0.8 million for FY 2018 through FY 2023 capital investments mainly related to the DG project review and (7) a $0.1 million decrease in O&M expense compared to the approved FY 2024 plan. Additionally, the FY 2024 revenue requirement was increased for the FY 2023 and FY 2024 tax hold harmless adjustment of $1.6 million as described in the testimony of Ms. Hawk.

Q. Please describe the impact of the implementation of new base distribution rates that were approved by the PUC in Docket No. 4770 and put into effect on September 1, 2018 on the FY 2023 ISR revenue requirement recoverable through the FY 2024 ISR factor.

A. The ISR mechanism was established to allow the Company to recover outside of base rates, costs of capital investment in electric distribution system infrastructure, safety and reliability. When new base distribution rates are implemented, as was the case in

Docket No. 4770, the costs that are recovered and associated with pre-rate case ISR capital investment cease to be recovered through a separate ISR factor. Instead, these costs are recovered through base distribution rates, and the underlying ISR capital investment becomes a component of base distribution rate base from that point forward. In November 2017, the Company filed an application with the PUC seeking a change in base distribution rates for its gas and electric distribution businesses. The proceeding culminated with the Commission's approval of a settlement agreement with the Division and numerous intervenors establishing new base distribution rates for the Company. The Company's proposed rate base reflected projected capital investments through August 31, 2019. In its base rate request, the Company proposed to maintain consistency with the existing ISR mechanism for the FY 2019, FY 2020, FY 2021, and FY 2022 periods. Consequently, the forecast used to develop rate base in the first year of the distribution rate case included actual capital investment through the test year ending June 30, 2017, nine months of the ISR approved capital investment levels for vintage FY 2018, 12 months of vintage FY 2019 investment and five months of vintage FY 2020 investment (using the FY 2018 ISR approved level of plant additions as a proxy for FY 2018, FY 2019, and FY 2020). The FY 2022 revenue requirement for FY 2018 through FY 2022 ISR investments that are incremental to the estimated level of investment assumed in base rates reflects a full year of revenue requirement as none of these incremental investments are included in the Company's rate-base. These incremental FY vintage amounts are to remain in the ISR recovery mechanism as provided for in the terms of the Docket No. 4770 approved Settlement Agreement until a future proceeding that rolls these amounts into base rates.

Q. Does the updated FY 2024 revenue requirement reflect the calculation of the excess deferred income tax amounts.

A. Yes. The excess deferred income taxes are calculated on Line 27, Page 2, of Attachment JDO-1. This calculation is further explained in the prefiled testimony of Ms. Hawk.

Q. Are there any tax updates to the FY 2023 revenue requirement reflected in the FY 2024 Electric ISR Reconciliation?

A. Yes. Please see the testimony of Ms. Hawk for a description of the tax updates reflected in the FY 2024 Electric ISR revenue requirement.

Q. **Please summarize the updated FY 2024 Electric ISR revenue requirement.**

A. As shown on Page 1 of Attachment JDO-1, the Company's FY 2024 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's VM activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. The description of these elements and the related amounts are supported by the direct testimony and supporting attachments of Ms. Gooding. Line 4 reflects the actual FY 2024 revenue requirement related to O&M expenses of $14,929,779.

As shown on Page 1, at Line 15 of Attachment JDO-1, the FY 2024 revenue requirement associated with the Company's actual capital investment totals $39,026,367. As previously noted, the total FY 2024 capital investment component of revenue requirement includes (1) FY 2024 revenue requirement on vintages FY 2018 through FY 2024 ISR capital investments above or below the level of capital investment reflected in base distribution rates in Docket No. 4770; (2) the FY 2024 property tax recovery mechanism component; and (3) the FY 2023 revenue requirement true-up for changes to previously estimated tax depreciation expense and NOL position to align with the Company's FY 2023 tax return. The total actual FY 2024 ISR Plan revenue requirement for both O&M expenses and capital investment of $53,956,146 is shown on Line 16. Additionally, the FY 24 Revenue Requirement is adjusted for the FY 2023 and FY 2024 Hold Harmless adjustments on Lines 17 and 18, as further described in the testimony of Ms. Hawk, and the DG project review adjustment on Line 20 for the impact on the FY 2018 through 2023 revenue requirement. This results in a net FY 2024 Revenue Requirement of $54,282,082 on Line 21.

Q. Please describe how the attachment to your testimony is structured.

A. Page 1 of Attachment JDO-1 summarizes the individual components of the updated FY 2024 ISR revenue requirement. Page 1, Column (a) reflects the approved FY 2024 Electric ISR Plan revenue requirement on projected VM and I&M program costs and incremental ISR capital investment as well as the projected FY 2024 property tax recovery adjustment. Page 1, Column (b) represents (1) the O&M components for FY 2024; (2) FY 2024 ISR revenue requirements for incremental FY 2018 through FY 2024 ISR investments – not included in the Company's base rates in Docket No. 4770 – and as supported with detailed calculations on Attachment JDO-1, Pages 2, 5, 10, 13, 17, 20 and 23; (3) FY 2024 property tax adjustment on incremental capital not included in the Company's base rates in Docket No. 4770; (4) the reconciliation on Line 14 of the approved FY 2023 ISR revenue requirement for vintage FY 2023 plant additions with the actual vintage FY 2023 revenue requirement on those investments related to tax deductibility updates; (5) the hold harmless adjustments related to the impacts of the Acquisition; and (6) the DG project review adjustment. As discussed in Ms. Hawk's testimony, this reconciliation in item (4) is necessary because the actual level of tax deductibility on FY 2023 investments was not known when the Company filed the FY 2023 ISR reconciliation and FY 2024 ISR Plan proposals. A detailed calculation of the updated FY 2023 revenue requirement is presented on page 20 of Attachment JDO-1.

Q. Has the Company provided support for the actual level of FY 2024 ISR-eligible plant investments?

A. Yes. The description of the FY 2024 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR mechanism are supported by the direct testimony and supporting attachment of Ms. Gooding. The ultimate revenue requirement on the ISR eligible plant additions equals the return on the investment (i.e., average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental ISR eligible plant additions for this purpose are intended to represent the net change in rate base for electric infrastructure investments, since the establishment of the Company's ISR mechanism effective April 1, 2011 and are defined as capital additions plus cost of removal, less annual depreciation expense included in the Company's rates, net of depreciation expense attributable to general plant. As discussed in the testimony of Ms. Gooding, the actual ISR eligible plant additions for FY 2024 totals $97.3 million associated with the Company's FY 2024 ISR Plan (electric infrastructure investment net of general plant).

Q. Please explain the distinction between non-discretionary and discretionary capital spending as they relate to the revenue requirement calculation.

A. 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. The amount of discretionary investment the Company is allowed to include in the revenue requirement calculation is subject to certain limitations. The amount of discretionary capital investment the Company uses in the revenue requirement must be no greater than the cumulative amount of discretionary project spend as approved by the PUC in this proceeding. This means that the discretionary investment is limited to the lesser of actual cumulative discretionary capital additions or spending, or cumulative discretionary spending approved by the PUC in this docket. For purposes of the FY 2024 revenue requirement, the lesser of these items was actual discretionary capital additions of $51,836,809, as shown on Attachment JDO-1, Page 35, Line 13, column (a), of which $51,836,809 was incremental to the amount of discretionary capital additions assumed in base rates.

Q. What is the updated revenue requirement associated with actual plant additions?

A. The updated FY 2024 revenue requirement, associated with the Company's actual FY 2018 through FY 2024 ISR eligible plant investments, totals $53,956,146. This amount includes the updated FY 2024 O&M components and revenue requirement on FY 2018 through FY 2024 incremental ISR investments, inclusion of the property tax recovery adjustment pursuant to the rate case settlement agreements in Docket No. 4323 and in Docket No. 4770, and the reconciliation of the approved FY 2023 ISR revenue requirements on vintage FY 2023 investments with the actual FY 2023 income tax deductibility on those investments.

Q. Please describe any changes to the presentation of the revenue requirement calculations in Attachment JDO-1 because of the Acquisition.

A. To reflect the impacts of the Acquisition, as discussed in Ms. Hawk's prefiled testimony, the calculations of the FY 2023 rate base and revenue requirement for the vintage plan years FY 2018 through FY 2023 were separated into two columns in Attachment JDO-1, Pages 2, 5, 8, 13, 17 and 20. The first FY 2023 column labeled as "NG, 4/1/22-5/24/2022", reflects the 54 days of National Grid ownership during the FY 2023 ISR. The second FY 2023 column labeled as "PPL, 5/25/22-3/31/23" reflects the period from Acquisition date through March 31, 2023, which represents the 311 days of PPL's ownership.

Q. Please describe the adjustment to increase the FY 2024 revenue requirement for the DG project review.

A. As described in the pre-filed testimony of Ms. Gooding, the Company decided in the FY 2023 Electric ISR Plan Reconciliation to remove $10.6 million of plant additions associated with DG projects from the revenue requirement until a review of each project is completed. That review was completed in FY 2024 and the FY 2024 revenue requirement reflects an adjustment to increase the revenue requirement to reflect the results of this final review on Attachment JDO-1, Page 1, Line 20.and Attachment JDO-1, Page 36, Line 27.

III. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2024 (a)	Actual Fiscal Year 2024 (b)	Variance Fiscal Year 2024 (c)=(b)-(a)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$13,950,000	$13,785,383	($164,617)
2	Current Year Inspection & Maintenance (I&M)	$738,000	$889,396	$151,396
3	Current Year Other Programs	$425,000	$255,000	($170,000)
4	**Total O&M Expense Component of Revenue Requirement**	**$15,113,000**	**$14,929,779**	**($183,221)**
	Capital Investment:			
5	Actual 2024 Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,898,402	$1,768,186	($130,216)
6	Actual 2024 Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$4,121,015	$4,028,265	($92,750)
7	Actual 2024 Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,848,269	$5,387,733	($460,536)
8	Actual 2024 Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$8,572,859	$8,369,846	($203,013)
9	Actual 2024 Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$5,183,040	$4,969,083	($213,957)
10	Actual 2024 Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base	$7,787,883	$4,737,008	($3,050,875)
11	Actual 2024 Revenue Requirement on FY 2024 Incremental Capital included in ISR Rate Base	$3,069,596	$2,886,887	($182,709)
12	Subtotal	$36,481,064	$32,147,009	($4,334,055)
13	FY 2024 Property Tax Recovery Adjustment	$5,403,526	$7,788,501	$2,384,975
14	True-Up for FY 2023 (Income Tax)		($909,143)	($909,143)
15	**Total Capital Investment Component of Revenue Requirement**	**$41,884,590**	**$39,026,367**	**($2,858,223)**
16	**Total Fiscal Year Revenue Requirement**	**$56,997,590**	**$53,956,146**	**($3,041,444)**
17	**FY 2024 Tax Hold Harmless Adjustment per Attachment NH-1**	(1,579,533)	(838,084)	$741,449
18	**FY 2023 Tax Hold Harmless True-Up Adjustment per Attachment NH-2**		868,312	$868,312
19	**Total Net Revenue Requirement**	**$55,418,057**	**$53,986,375**	**($1,431,683)**
20	**Additional Adjustment for DG Project review (FY 18 - FY 23 revenue requirement)**		**$295,707**	$295,707
21	**Total Net Revenue Requirement with DG review adjustment**	**$55,418,057**	**$54,282,082**	**($1,135,976)**
22	**Incremental Fiscal Year Rate Adjustment**		**($1,135,976)**	

Column/Line Notes:

Col (a)	Docket No. 22-53-EL, FY 2024 Electric ISR Plan, Section 5 ; Attachment 1 (C), Page 1 of 35, Column (b)
Col (b)	
1	Vegetation Management, Attachment NAG-1, Table 11
2	Other Operations and Maintenance, Attachment NAG-1, Table 12
3	Other Operations and Maintenance, Attachment NAG-1, Table 12
4	Sum of Lines 1 through 3
5	Page 2 of 36, Line 40 column (h)
6	Page 5 of 36, Line 42 column (g)
7	Page 10 of 36, Line 39 column (f)
8	Page 13 of 36, Line 40 column (e)
9	Page 17 of 36, Line 39 column (d)
10	Page 20 of 36, Line 39 column (c)
11	Page 23 of 36, Line 35 column (a)
12	Sum of Lines 5 through 11
13	Page 31 of 36, Line 91, Column (x) x 1,000
14	Page 20 of 36, Line 46, Column (a) & Column (b)
15	Sum of Lines 13 through 14
16	Line 4 + Line 15
17	Attachment NH-1, Page 1, Line 23, column (c)
18	Attachment NH-2, Page 1, Line 23, column (e)
19	Line 17 + Line 18
20	Page 33 of 36, Line 27, Column F, Represents additional adjustment in FY 2024
21	Line 19 + Line 20
22	Line 21 Col (b) - Line 21 Col (a)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2024 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 - 3/31/23 2023 (g)	Fiscal Year 2024 (h)
	Capital Investment Allowance										
1	*Non-Discretionary Capital*			$2,269,710							
	Discretionary Capital										
2	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 26 of 36, Line 4(a)		$16,907,966	$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		$16,907,966	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 26 of 36 , Line 10 ,Col (a)		($5,245,072)	$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		$22,153,038	$22,153,038	$22,153,038	$22,153,038	$22,153,038	$22,153,038	$22,153,038	$22,153,038
	Change in Net Capital Included in Rate Base										
7	Capital Included in Rate Base	Line 3		$16,907,966	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$16,907,966	$16,907,966	$16,907,966	$16,907,966	$16,907,966	$16,907,966	$16,907,966	$16,907,966
10	Cost of Removal	Page 26 of 36 , Line 7 ,Col (a)		$1,693,009	$0	$0	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$18,600,975**	**$18,600,975**	**$18,600,975**	**$18,600,975**	**$18,600,975**	**$18,600,975**	**$18,600,975**	**$18,600,975**
	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%
13	Number of days		2/						54	311	
14	Proration Percentage		2/						14.79%	85.21%	
15	Vintage Year Tax Depreciation:										
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 3 of 36, Line 29; then = Page 3 of 36, Column (e)		$13,351,493	$541,905	$501,219	$463,685	$428,855	$58,694	$510,206	$982,181
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$13,351,493	$13,893,398	$14,394,616	$14,858,302	$15,287,156	$15,345,850		
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/							$510,206	$1,492,387
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12	2/	$376,602	$722,189	$700,036	$700,036	$700,036	$103,567	$596,469	$700,036
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$376,602	$1,098,791	$1,798,827	$2,498,863	$3,198,899	$3,302,466	$3,898,935	$4,598,971
21	Cumulative Book / Tax Timer	Columns (a) through (f): Line 17 - Line 20, Then Line 18 - Line 20		$12,974,891	$12,794,607	$12,595,790	$12,359,439	$12,088,258	$12,043,384	($3,388,728)	($3,106,583)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (f)	3/							$3,302,466	$3,302,466
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22								($86,263)	$195,882
24	Effective Tax Rate		4/	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		$2,724,727	$2,686,868	$2,645,116	$2,595,482	$2,538,534	$2,529,111	($18,115)	$41,135
26	Less: FY 2018 Federal NOL (Generation) / Utilization	Year 1 = Page 26 of 36 , 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
27	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,368,851	$1,368,851	$1,368,851	$1,368,851	$1,368,851	$1,368,851	$1,368,851	$1,368,851
28	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 27		$1,095,080	$1,057,220	$1,015,468	$965,835	$908,887	$899,463	$1,350,736	$1,409,986
	Rate Base Calculation:										
29	Cumulative Incremental Capital Included in Rate Base	Line 11		$18,600,975	$18,600,975	$18,600,975	$18,600,975	$18,600,975	$18,600,975	$18,600,975	$18,600,975
30	Accumulated Depreciation	-Line 20		($376,602)	($1,098,791)	($1,798,827)	($2,498,863)	($3,198,899)	($3,302,466)	($3,898,935)	($4,598,971)
31	Deferred Tax Reserve	-Line 28		($1,095,080)	($1,057,220)	($1,015,468)	($965,835)	($908,887)	($899,463)	($1,350,736)	($1,409,986)
32	Year End Rate Base before Deferred Tax Proration	Sum of Lines 29 through 31		$17,129,294	$16,444,964	$15,786,680	$15,136,278	$14,493,190	$14,399,046	$13,351,305	$12,592,018
	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/	$8,564,647	$16,787,129	$16,115,822	$15,461,479	$14,814,734	$13,922,247	$13,922,247	$12,971,661
34	Proration Adjustment	Page 4 of 36, Line 41				($1,792)	($2,130)	($2,444)	($1,182)	($1,182)	$7,075
35	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$8,564,647	$16,787,129	$16,114,030	$15,459,348	$14,812,289	$13,921,065	$13,921,065	$12,978,736
36	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
37	Proration	Line 14	2/						14.79%	85.21%	
38	Return and Taxes	Cols (a) through (e) and (h): L 35 * L 36; Cols (f) through (g): L 35 * L 36 * L 37	2/	$704,870	$1,381,581	$1,326,185	$1,272,304	$1,219,051	$169,501	$976,202	$1,068,150
39	Book Depreciation	Line 19		$376,602	$722,189	$700,036	$700,036	$700,036	$103,567	$596,469	$700,036
40	**Annual Revenue Requirement**	Line 38 + Line 39		**$1,081,472**	**$2,103,770**	**$2,026,221**	**$1,972,340**	**$1,919,087**	**$273,068**	**$1,572,671**	**$1,768,186**

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) and (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.
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) and (g) 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 (g). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
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 36, Line 3		$16,907,966		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%					
3	Capital Repairs Deduction	Line 1 * Line 2		$1,521,717	NG MACRS basis:	Line 22, Column (a)		$7,506,643	
4		`						Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$16,907,966	FY Mar-2018	3.750%		$281,499	$13,351,493
7	Less Capital Repairs Deduction	- Line 3		($1,521,717)	FY Mar-2019	7.219%		$541,905	$13,893,397
8	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7		$15,386,249	FY Mar-2020	6.677%		$501,219	$14,394,616
9	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2021	6.177%		$463,685	$14,858,301
10	Plant Eligible for Bonus Depreciation	Line 8 * Line 9		$15,386,249	FY Mar-2022	5.713%		$428,855	$15,287,156
11	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%	FY Mar-2023 (Apr-May 2022)	5.285%	0.782%	$58,694	$15,345,850
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)		$16,907,966	
15	Total Bonus Depreciation Rate	Line 11 + Line 12 + Line 13 + Line 14		51.21%	Cumulative Book Depreciation	- Page 2 of 36, Line 20, Col (f)		($3,302,466)	
16	Bonus Depreciation	Line 10 * Line 15		$7,879,606	PPL MACRS basis:	Line 14(e) + Line 15(e)		$13,605,501	
17									
18	Remaining Tax Depreciation				Mar-2023 (Jun-Mar 2023)	3.750%		$510,206	$510,206
19	Plant Additions	Line 1		$16,907,966	Mar 2024	7.219%		$982,181	$1,492,387
20	Less Capital Repairs Deduction	Line 3		$1,521,717	Mar 2025	6.677%		$908,439	$2,400,827
21	Less Bonus Depreciation	Line 16		$7,879,606	Mar 2026	6.177%		$840,412	$3,241,238
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 19 - Line 20 - Line 21		$7,506,643	Mar 2027	5.713%		$777,282	$4,018,521
23	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar 2028	5.285%		$719,051	$4,737,571
24	Remaining Tax Depreciation	Line 22 * Line 23		$281,499	Mar 2029	4.888%		$665,037	$5,402,608
25					Mar 2030	4.522%		$615,241	$6,017,849
26	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662	Mar 2031	4.462%		$607,077	$6,624,926
27	Cost of Removal	Page 2 of 36, Line 10		$1,693,009	Mar 2032	4.461%		$606,941	$7,231,868
28					Mar 2033	4.462%		$607,077	$7,838,945
29	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 16, 24, 26, and 27		$13,351,493	Mar 2034	4.461%		$606,941	$8,445,887
30					Mar 2035	4.462%		$607,077	$9,052,964
31					Mar 2036	4.461%		$606,941	$9,659,905
32					Mar 2037	4.462%		$607,077	$10,266,983
33					Mar 2038	4.461%		$606,941	$10,873,924
34					Mar 2039	4.462%		$607,077	$11,481,002
35					Mar 2040	4.461%		$606,941	$12,087,943
36					Mar 2041	4.462%		$607,077	$12,695,020
37					Mar 2042	4.461%		$606,941	$13,301,962
38					Mar 2043	2.231%		$303,539	$13,605,501
39						92.78%		$13,605,501	
40									

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

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

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation	See the corresponding Fiscal Year on Page 2 of 36, Line 19. Note there are 2 columns to sum for FY23.	$700,036	$700,036	$700,036	$700,036
2	Bonus Depreciation		$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 2 of 36, Line 16. Note there are 2 columns to sum for FY23.	($428,855)	($568,900)	($982,181)	($908,439)
4	FY18 tax (gain)/loss on retirements		$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$271,181	$131,136	($282,145)	($208,403)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$56,948	$27,539	($59,250)	($43,765)
	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	$0
12	Effective Tax Rate		21%	21%	21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$56,948	$27,539	($59,250)	($43,765)
15	Net Operating Loss		$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$56,948	$27,539	($59,250)	($43,765)
	Allocation of FY 2018 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$271,181	$131,136	($282,145)	($208,403)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$271,181	$131,136	($282,145)	($208,403)
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	$0
22	Allocated FY 2018 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	$56,948	$27,539	($59,250)	($43,765)

Line No.		(e)	(f)	(g)	(h)	(i)	(j)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23	FY24	FY25
26	April	30	91.78%	$4,356	$2,106	($4,532)	($3,347)
27	May	31	83.29%	$3,953	$1,911	($4,112)	($3,038)
28	June	30	75.07%	$3,563	$1,723	($3,707)	($2,738)
29	July	31	66.58%	$3,159	$1,528	($3,287)	($2,428)
30	August	31	58.08%	$2,756	$1,333	($2,868)	($2,118)
31	September	30	49.86%	$2,366	$1,144	($2,462)	($1,819)
32	October	31	41.37%	$1,963	$949	($2,043)	($1,509)
33	November	30	33.15%	$1,573	$761	($1,637)	($1,209)
34	December	31	24.66%	$1,170	$566	($1,217)	($899)
35	January	31	16.16%	$767	$371	($798)	($590)
36	February	28	8.49%	$403	$195	($419)	($310)
37	March	31	0.00%	$0	$0	$0	$0
38	Total	365		$26,030	$12,587	($22,550)	($16,657)
39	Deferred Tax Without Proration	Line 25		$56,948	$27,539	($59,250)	($43,765)
40	Average Deferred Tax without Proration	Line 25 * 50%		$28,474	$13,769	($29,625)	($21,882)
41	Proration Adjustment	Line 38 - Line 40		($2,444)	($1,182)	$7,075	$5,226

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2024 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 - 5/24/22 2023 (e)	PPL 5/25/22 - 3/31/23 2023 (f)	Fiscal Year 2024 (g)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*			$6,316,248						
2	*Discretionary Capital* 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 26 of 36, Line 4(b)		$31,803,024	$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)		$31,803,024	$0	$0	$0	$0	$0	$0
5	Retirements	Page 26 of 36 , Line 10 ,Col (b)		($10,649,479)	$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		$42,452,503	$42,452,503	$42,452,503	$42,452,503	$42,452,503	$42,452,503	$42,452,503
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3, Column (a)		$31,803,024	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$31,803,024	$31,803,024	$31,803,024	$31,803,024	$31,803,024	$31,803,024	$31,803,024
10	Cost of Removal	Page 26 of 36 , Line 7 ,Col (b)		$361,723						
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$32,164,747**	**$32,164,747**	**$32,164,747**	**$32,164,747**	**$32,164,747**	**$32,164,747**	**$32,164,747**
	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%
13	Number of days		2/					54	311	
14	Proration Percentage		2/					14.79%	85.21%	
15	Vintage Year Tax Depreciation:									
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 6 of 36, Line 28 Then = Page 6 of 36 Column (e)		$9,891,758	$1,779,269	$1,645,682	$1,522,447	$208,319	$1,008,303	$1,941,051
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$9,891,758	$11,671,027	$13,316,709	$14,839,156	$15,047,475		
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/						$1,008,303	$2,949,354
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$691,976	$1,341,499	$1,341,499	$1,341,499	$198,468	$1,143,031	$1,341,499
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$691,976	$2,033,475	$3,374,974	$4,716,473	$4,914,941	$6,057,972	$7,399,471
21	Cumulative Book / Tax Timer	Columns (a) through(e): Line 17 - Line 20, Then Line 18 - Line 20		$9,199,782	$9,637,552	$9,941,735	$10,122,683	$10,132,534	($5,049,669)	($4,450,117)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (e)	3/						$4,914,941	$4,914,941
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22							($134,728)	$464,824
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 (e): Line 21 * Line 24, Then Line 23 * Line 24		$1,931,954	$2,023,886	$2,087,764	$2,125,763	$2,127,832	($28,293)	$97,613
26	Add: FY 2019 Federal NOL (Generation) / Utilization	Page 26 of 36 , Line 15 ,Col (b)	3/	$991,622	$991,622	$991,622	$991,622	$991,622	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 25 through 26		$2,923,576	$3,015,508	$3,079,386	$3,117,385	$3,119,454	($28,293)	$97,613
	Rate Base Calculation:									
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$32,164,747	$32,164,747	$32,164,747	$32,164,747	$32,164,747	$32,164,747	$32,164,747
29	Accumulated Depreciation	-Line 20		($691,976)	($2,033,475)	($3,374,974)	($4,716,473)	($4,914,941)	($6,057,972)	($7,399,471)
30	Deferred Tax Reserve	-Line 27		($2,923,576)	($3,015,508)	($3,079,386)	($3,117,385)	($3,119,454)	$28,293	($97,613)
31	Year End Rate Base before Deferred Tax Proratior	Sum of Lines 28 through 30		$28,549,195	$27,115,764	$25,710,387	$24,330,889	$24,130,352	$26,135,068	$24,667,663
	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/	$14,274,598	$27,832,480	$26,413,076	$25,020,638	$25,232,978	$25,232,978	$25,401,365
33	Proration Adjustment	Page 7 of 36, Line 43		$0	$0	$0	($514)	($955)	($955)	$7,118
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$14,274,598	$27,832,480	$26,413,076	$25,020,124	$25,232,023	$25,232,023	$25,408,484
35	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration Percentage	Line 14	2/					14.79%	85.21%	
37	Return and Taxes	Cols (a) through (d) and (g): L 34 * L 35; Cols (e) and (f): L 34 * L 35 * L 36	2/	$1,174,799	$2,290,613	$2,173,796	$2,059,156	$307,222	$1,769,373	$2,091,118
38	Book Depreciation	Line 19		$691,976	$1,341,499	$1,341,499	$1,341,499	$198,468	$1,143,031	$1,341,499
39	Annual Revenue Requirement	Line 37 + Line 38		$1,866,775	$3,632,112	$3,515,295	$3,400,655	$505,691	$2,912,404	$3,432,617
40	Revenue Requirement of Plant	Year 1 = Line 39*7/12, Then = Line 39		$1,088,952	$3,632,112	$3,515,295	$3,400,655	$505,691	$2,912,404	$3,432,617
41	Revenue Requirement of Intangibl	Page 8 of 36, Line 34, Column (l) ~ (aa		$434,302	$705,779	$655,914	$617,127	$81,808	$548,352	$595,648
42	**Revenue Requirement**	Line 40 + Line 41		**$1,523,254**	**$4,337,891**	**$4,171,209**	**$4,017,782**	**$587,499**	**$3,460,756**	**$4,028,265**

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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

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4/ Columns (e) and (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 (d) 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
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
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 5 of 36, Line 3		$31,803,024		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.68%					
3	Capital Repairs Deduction	Line 1 * Line 2		$3,078,557	MACRS basis:	Line 22, Column (a)		$24,647,029	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$31,803,024	FY Mar-2019	3.750%		$924,264	$9,891,758
7	Plant Additions			$0	FY Mar-2020	7.219%		$1,779,269	$11,671,027
8	Less Capital Repairs Deduction	Line 3		$3,078,557	FY Mar-2021	6.677%		$1,645,682	$13,316,709
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$28,724,467	FY Mar-2022	6.177%		$1,522,447	$14,839,156
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2023 (Apr-May 2022)	5.713%	0.85%	$208,319	$15,047,475
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$28,724,467					
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)		$31,803,024	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		14.20%	Cumulative Book Depreciation	- Page 5 of 36, Line 20, Col (e)		($4,914,941)	
15	Bonus Depreciation	Line 11 * Line 14		$4,077,438	PPL MACRS basis:	Line 13(e) + Line 14(e)		$26,888,082	
16									
17	Remaining Tax Depreciation				FY Mar-2023 (Jun-Mar 2023)	3.750%		$1,008,303	$1,008,303
18	Plant Additions	Line 1		$31,803,024	Mar-2024	7.219%		$1,941,051	$2,949,354
19	Less Capital Repairs Deduction	Line 3		$3,078,557	Mar-2025	6.677%		$1,795,317	$4,744,671
20	Less Bonus Depreciation	Line 15		$4,077,438	Mar-2026	6.177%		$1,660,877	$6,405,548
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$24,647,029	Mar-2027	5.713%		$1,536,116	$7,941,664
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2028	5.285%		$1,421,035	$9,362,699
23	Remaining Tax Depreciation	Line 21 * Line 22		$924,264	Mar-2029	4.888%		$1,314,289	$10,676,989
24					Mar-2030	4.522%		$1,215,879	$11,892,868
25	FY19 (Gain)/Loss incurred due to retirements	Per Tax Department	3/	$1,449,776	Mar-2031	4.462%		$1,199,746	$13,092,614
26	Cost of Removal	Page 5 of 36, Line 10		$361,723	Mar-2032	4.461%		$1,199,477	$14,292,091
27					Mar-2033	4.462%		$1,199,746	$15,491,838
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$9,891,758	Mar-2034	4.461%		$1,199,477	$16,691,315
29					Mar-2035	4.462%		$1,199,746	$17,891,061
30					Mar-2036	4.461%		$1,199,477	$19,090,539
31					Mar-2037	4.462%		$1,199,746	$20,290,285
32					Mar-2038	4.461%		$1,199,477	$21,489,762
33					Mar-2039	4.462%		$1,199,746	$22,689,508
34					Mar-2040	4.461%		$1,199,477	$23,888,986
35					Mar-2041	4.462%		$1,199,746	$25,088,732
36					Mar-2042	4.461%		$1,199,477	$26,288,209
37					Mar-2043	2.231%		$599,873	$26,888,082
38						100.000%		$26,888,082	
39									

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

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

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation - Excl. Intangibles	See the corresponding Fiscal Year on Page 5 of 36, Line 19. Note there are 2 columns to sum for FY23.	$1,341,499	$1,341,499	$1,341,499	$1,341,499
2	Book Depreciation - Intangibles	See the corresponding Fiscal Year on Page 8 of 36, Line 21 - Line 20. Note there are 2 columns to sum for FY23.	$494,375	$494,375	$494,375	$494,375
3	Bonus Depreciation		$0	$0	$0	$0
4	Remaining MACRS Tax Depreciation - Excl. Intangibles	See the corresponding Fiscal Year on Page 5 of 36, Line 16. Note there are 2 columns to sum for FY23.	($1,522,447)	($1,216,622)	($1,941,051)	($1,795,317)
5	Remaining MACRS Tax Depreciation - Intangibles	See the corresponding Fiscal Year on Page 8 of 36, Line 18 - Line 17. Note there are 2 columns to sum for FY23.	($256,432)	($513,297)	($684,550)	($228,081)
6	FY 2019 tax (gain)/loss on retirements		$0	$0	$0	$0
7	Cumulative Book / Tax Timer	Sum of Lines 1 through 6	$56,995	$105,955	($789,726)	($187,524)
8	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
9	Deferred Tax Reserve	Line 7 * Line 8	$11,969	$22,250	($165,843)	($39,380)
	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	$0
14	Effective Tax Rate		21%	21%	21%	21%
15	Deferred Tax Reserve	Line 13 × Line 14	$0	$0	$0	$0
16	Total Deferred Tax Reserve	Line 9 + Line 15	$11,969	$22,250	($165,843)	($39,380)
17	Net Operating Loss		$0	$0	$0	$0
18	Net Deferred Tax Reserve	Line 16 + Line 17	$11,969	$22,250	($165,843)	($39,380)
	Allocation of FY 2019 Estimated Federal NOL					
19	Cumulative Book/Tax Timer Subject to Proration	Line 7	$56,995	$105,955	($789,726)	($187,524)
20	Cumulative Book/Tax Timer Not Subject to Proration	Line 13	$0	$0	$0	$0
21	Total Cumulative Book/Tax Timer	Line 19 + Line 20	$56,995	$105,955	($789,726)	($187,524)
22	Total FY 2019 Federal NOL		$0	$0	$0	$0
23	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 20 ÷ Line 21) × Line 22	$0	$0	$0	$0
24	Allocated FY 2019 Federal NOL Subject to Proration	(Line 19 ÷ Line 21) × Line 22	$0	$0	$0	$0
25	Effective Tax Rate		21%	21%	21%	21%
26	Deferred Tax Benefit subject to proration	Line 24 × Line 25	$0	$0	$0	$0
27	Net Deferred Tax Reserve subject to proration	Line 9 + Line 26	$11,969	$22,250	($165,843)	($39,380)

Line No.	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(g) FY22	(h) FY23	(i) FY24	(j) FY25
28	April	30	91.78%	$915	$1,702	($12,684)	($3,012)
29	May	31	83.29%	$831	$1,544	($11,511)	($2,733)
30	June	30	75.07%	$749	$1,392	($10,375)	($2,463)
31	July	31	66.58%	$664	$1,234	($9,201)	($2,185)
32	August	31	58.08%	$579	$1,077	($8,027)	($1,906)
33	September	30	49.86%	$497	$925	($6,891)	($1,636)
34	October	31	41.37%	$413	$767	($5,717)	($1,358)
35	November	30	33.15%	$331	$615	($4,581)	($1,088)
36	December	31	24.66%	$246	$457	($3,408)	($809)
37	January	31	16.16%	$161	$300	($2,234)	($530)
38	February	28	8.49%	$85	$157	($1,174)	($279)
39	March	31	0.00%	$0	$0	$0	$0
40	Total	365		$5,471	$10,170	($75,803)	($18,000)
41	Deferred Tax Without Proration	Line 27		$11,969	$22,250	($165,843)	($39,380)
42	Average Deferred Tax without Proration	Line 39 * 50%		$5,984	$11,125	($82,921)	($19,690)
43	Proration Adjustment	Line 40 - Line 42		($514)	($955)	$7,118	$1,690

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 27 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2024 Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	FY19 Total (c) = (a) + (b)	FY 20 Total (f) = (d) + (e)	FY 21 Total (i) = (g) + (h)	FY 22 Total (l) = (j) + (k)	FY Mar-2023 (Apr-May 2022) (o) = (m) + (n)	FY Mar-2023 (Jun 2022 -Mar 2023) (r) = (p) + (q)	FY 24 Total (u) = (s) + (t)	FY 25 Total (x) = (v) + (w)
	Capital Investment						NG	PPL	PPL	PPL
1	Start of Rev. Req. Period		09/01/18	04/01/19	04/01/20	04/01/21	04/01/22	05/25/22	04/01/23	04/01/24
2	End of Rev. Req. Period		03/31/19	03/31/20	03/31/21	03/31/22	05/24/22	03/31/23	03/31/24	03/31/25
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	$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	$3,378,230	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,540,045	$1,112,344	$617,969
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,540,045	$1,112,344	$617,969	$123,594
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$1,573,382	$1,326,195	$865,157	$370,781
	Deferred Tax Calculation:									
11	Total Spend									
12	In Service Date									
13	Tax Amortizaton Period	Page 9 of 36								
14	Tax Expensing	Per Tax Department	$0	$0	$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	$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%)	$1,153,427	$1,153,427	$2,691,675	$3,204,194	$3,460,626	$0	$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%)	$1,153,427	$2,691,675	$3,204,194	$3,460,626	$3,460,626	$513,297	$1,197,847	$1,425,928
19	Average Acc. Tax Balance	(Line 17 + Line 18) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410	$3,460,626	$256,649	$855,572	$1,311,887
20	Beginning Acc. Dep. Balance	Line 5 - Line 8	$82,396	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581	$2,348,282	$2,842,657
21	Ending Acc. Dep. Balance	Line 5 - Line 9	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581	$2,348,282	$2,842,657	$3,337,032
22	Average Acc. Dep. Balance	(Line 20 + Line 21) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719	$1,887,244	$2,134,432	$2,595,470	$3,089,845
23	Number of days									
24	Proration Percentage									
25	Average Book / Tax Timer	Line 19 - Line 22	$926,838	$1,304,582	$1,835,590	$1,725,691	$232,774	($1,599,974)	($1,739,898)	($1,777,957)
26	Effective Tax Rate									
27	Deferred Tax Reserve	Line 25 × Line 26	$194,636	$273,962	$385,474	$362,395	$48,883	($335,995)	($365,378)	($373,371)
	Rate Base Calculation:									
28	Average Book Balance	Line 10	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$232,774	$1,129,991	$865,157	$370,781
29	Deferred Tax Reserve	Line 27	$194,636	$273,962	$385,474	$362,395	$48,883	($335,995)	($365,378)	($373,371)
30	Average Rate Base	Line 28 - Line 29	$3,039,402	$2,568,695	$1,962,808	$1,491,512	$183,892	$1,465,985	$1,230,535	$744,152
	Revenue Requirement Calculation:									
31	Pre-Tax ROR	year 1 = Page 34 of 36, Line 27, column (e)×7÷12 Then = Page 34 of 36, Line 27(e)								
32	Return and Taxes	Line 30 × Line 31	$145,917	$211,404	$161,539	$122,751	$15,134	$120,651	$101,273	$61,244
33	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375	$66,674	$427,701	$494,375	$494,375
34	Annual Revenue Requirement	Line 32 + Line 33	$434,302	$705,779	$655,914	$617,127	$81,808	$548,352	$595,648	$555,619

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
MACRS Tables For Information Systems

Line	Annual Rate			Monthly Cumulative Rate				
No.	Year			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
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2024 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 - 5/24/22 2023 (d)	PPL 5/25/22 - 3/31/23 2023 (e)	Fiscal Year 2024 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*			$27,712,863					
	Discretionary Capital								
2	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 26 of 36, Line 4(c)		$67,310,198	$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		$67,310,198	$0	$0	$0	$0	$0
5	Retirements	Page 26 of 36 , Line 10 ,Col (c)		$4,015,632	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$63,294,566	$63,294,566	$63,294,566	$63,294,566	$63,294,566	$63,294,566
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$67,310,198	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 30 of 36, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$38,197,828	$38,197,828	$38,197,828	$38,197,828	$38,197,828	$38,197,828
10	Cost of Removal	Page 26 of 36 , Line 7 ,Col (c)		$11,332,719					
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$49,530,546**	**$49,530,546**	**$49,530,546**	**$49,530,546**	**$49,530,546**	**$49,530,546**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 28 of 36, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/				54	311	
14	Proration Percentage		2/				14.79%	85.21%	
15	Vintage Year Tax Depreciation:								
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 11 of 36, Line 28, Then = Page 11 of 36, Column (e)		$23,485,409	$4,297,773	$3,975,098	$544,058	$2,325,526	$4,476,792
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$23,485,409	$27,783,182	$31,758,279	$32,302,337		
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/					$2,325,526	$6,802,318
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$1,000,054	$2,000,108	$2,000,108	$295,906	$1,704,202	$2,000,108
20	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$1,000,054	$3,000,162	$5,000,271	$5,296,177	$7,000,379	$9,000,487
21	Cumulative Book / Tax Timer	Columns (c) & (d): Line 17 - Line 20, Then Line 18 - Line 20		$22,485,354	$24,783,019	$26,758,009	$27,006,160	($4,674,853)	($2,198,169)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (d)	3/					$5,296,177	$5,296,177
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22						$621,324	$3,098,008
24	Effective Tax Rate			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		$4,721,924	$5,204,434	$5,619,182	$5,671,294	$130,478	$650,582
26	Add: FY 2020 Federal NOL (Generation) / Utilization	Page 26 of 36, Line 15, Col (c)	3/	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$3,258,944	$3,741,454	$4,156,201	$4,208,313	$130,478	$650,582
	Rate Base Calculation:								
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$49,530,546	$49,530,546	$49,530,546	$49,530,546	$49,530,546	$49,530,546
29	Accumulated Depreciation	-Line 20		($1,000,054)	($3,000,162)	($5,000,271)	($5,296,177)	($7,000,379)	($9,000,487)
30	Deferred Tax Reserve	-Line 27		($3,258,944)	($3,741,454)	($4,156,201)	($4,208,313)	($130,478)	($650,582)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$45,271,548	$42,788,930	$40,374,074	$40,026,056	$42,399,689	$39,879,477
	Revenue Requirement Calculation:								
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 * Page 16 of 36, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$16,518,313	$44,030,239	$41,581,502	$41,386,882	$41,386,882	$41,139,583
33	Proration Adjustment	Page 12 of 36, Line 41		$30,912	$18,700	$17,802	$7,837	$7,837	$22,324
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$16,549,225	$44,048,939	$41,599,304	$41,394,719	$41,394,719	$41,161,907
35	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/				14.79%	85.21%	
37	Return and Taxes	Cols (a) through (c) and (f): L 34 * L 35; Cols (d) and (e): L 34 * L 35 * L 36	2/	$1,362,001	$3,625,228	$3,423,623	$504,018	$2,902,768	$3,387,625
38	Book Depreciation	Line 19		$1,000,054	$2,000,108	$2,000,108	$295,906	$1,704,202	$2,000,108
39	**Annual Revenue Requirement**	Line 37 + Line 38		**$2,362,055**	**$5,625,336**	**$5,423,731**	**$799,924**	**$4,606,970**	**$5,387,733**
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 28 of 36, Line 3, Col (e))
2/ Columns (d) and (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.
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) and (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 (c) 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
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
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 10 of 36, Line 3		$67,310,198	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%					
3	Capital Repairs Deduction	Line 1 * Line 2		$5,728,098	NG MACRS basis:	Line 22, Column (a)		$59,534,187	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Proration	MACRS	Tax Depr
6	Plant Additions	Line 1		$67,310,198	FY Mar-2020	3.750%		$2,232,532	$23,485,409
7	Plant Additions			$0	FY Mar-2021	7.219%		$4,297,773	$27,783,182
8	Less Capital Repairs Deduction	Line 3		$5,728,098	FY Mar-2022	6.677%		$3,975,098	$31,758,279
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$61,582,100	FY Mar-2023 (Apr-May 2022)	6.177%	0.914%	$544,058	$32,302,337
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%					
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$61,582,100	PPL Acquisition - May 25, 2022				
12	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%	Book Cost	Line 1, Column (a)		$67,310,198	
13	Bonus Depreciation Rate	1 * 0% * 25%		0.00%	Cumulative Book Depreciation	- Page 10 of 36, Line 20, Col (d)		($5,296,177)	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		3.33%	PPL MACRS basis:	Line 12(e) + Line 13(e)		$62,014,021	
15	Bonus Depreciation	Line 11 * Line 14		$2,047,913					
16					FY Mar-2023 (Jun-Mar 2023)	3.750%		$2,325,526	$2,325,526
17	Remaining Tax Depreciation				Mar-2024	7.219%		$4,476,792	$6,802,318
18	Plant Additions	Line 1		$67,310,198	Mar-2025	6.677%		$4,140,676	$10,942,994
19	Less Capital Repairs Deduction	Line 3		$5,728,098	Mar-2026	6.177%		$3,830,606	$14,773,600
20	Less Bonus Depreciation	Line 15		$2,047,913	Mar-2027	5.713%		$3,542,861	$18,316,461
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$59,534,187	Mar-2028	5.285%		$3,277,441	$21,593,902
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2029	4.888%		$3,031,245	$24,625,148
23	Remaining Tax Depreciation	Line 21 * Line 22		$2,232,532	Mar-2030	4.522%		$2,804,274	$27,429,422
24					Mar-2031	4.462%		$2,767,066	$30,196,487
25	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147	Mar-2032	4.461%		$2,766,445	$32,962,933
26	Cost of Removal	Page 10 of 36, Line 10		$11,332,719	Mar-2033	4.462%		$2,767,066	$35,729,998
27					Mar-2034	4.461%		$2,766,445	$38,496,444
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$23,485,409	Mar-2035	4.462%		$2,767,066	$41,263,509
29					Mar-2036	4.461%		$2,766,445	$44,029,955
30					Mar-2037	4.462%		$2,767,066	$46,797,020
31					Mar-2038	4.461%		$2,766,445	$49,563,466
32					Mar-2039	4.462%		$2,767,066	$52,330,531
33					Mar-2040	4.461%		$2,766,445	$55,096,977
34					Mar-2041	4.462%		$2,767,066	$57,864,043
35					Mar-2042	4.461%		$2,766,445	$60,630,488
36					Mar-2043	2.231%		$1,383,533	$62,014,021
37						100.000%		$62,014,021	
38									

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

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

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation	See the corresponding Fiscal Year on Page 10 of 36, Line 19. Note there are 2 columns to sum for FY23.	$2,000,108	$2,000,108	$2,000,108	$2,000,108
2	Bonus Depreciation		$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 10 of 36, Line 16. Note there are 2 columns to sum for FY23.	($3,975,098)	($2,869,583)	($4,476,792)	($4,140,676)
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	($1,974,989)	($869,475)	($2,476,684)	($2,140,568)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($414,748)	($182,590)	($520,104)	($449,519)
	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	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($414,748)	($182,590)	($520,104)	($449,519)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($414,748)	($182,590)	($520,104)	($449,519)
	Allocation of FY 2020 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5	($1,974,989)	($869,475)	($2,476,684)	($2,140,568)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($1,974,989)	($869,475)	($2,476,684)	($2,140,568)
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0	$0	$0	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0	$0
22	Allocated FY 2020 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	($414,748)	($182,590)	($520,104)	($449,519)

Line No.	Proration Calculation	Number of Days in Month (e)	Proration Percentage (f)	FY22 (g)	FY23 (h)	FY24 (i)	FY25 (j)
26	April	30	91.78%	($31,722)	($13,965)	($39,780)	($34,381)
27	May	31	83.29%	($28,786)	($12,673)	($36,099)	($31,200)
28	June	30	75.07%	($25,945)	($11,422)	($32,536)	($28,121)
29	July	31	66.58%	($23,010)	($10,130)	($28,855)	($24,939)
30	August	31	58.08%	($20,075)	($8,838)	($25,174)	($21,758)
31	September	30	49.86%	($17,234)	($7,587)	($21,612)	($18,679)
32	October	31	41.37%	($14,298)	($6,295)	($17,931)	($15,497)
33	November	30	33.15%	($11,458)	($5,044)	($14,368)	($12,418)
34	December	31	24.66%	($8,522)	($3,752)	($10,687)	($9,237)
35	January	31	16.16%	($5,587)	($2,460)	($7,006)	($6,055)
36	February	28	8.49%	($2,935)	($1,292)	($3,681)	($3,182)
37	March	31	0.00%	$0	$0	$0	$0
38	Total	365		($189,572)	($83,458)	($237,728)	($205,465)
39	Deferred Tax Without Proration	Line 25		($414,748)	($182,590)	($520,104)	($449,519)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 16 of 36, Line 16, Col (e); then = Line 39 * 50%		($207,374)	($91,295)	($260,052)	($224,760)
41	Proration Adjustment	Line 38 - Line 40		$17,802	$7,837	$22,324	$19,294

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) & (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2024 Revenue Requirement on FY 2021 Actual Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	NG 4/1/22 - 5/24/22 2023 (c)	PPL 5/25/22 - 3/31/23 2023 (d)	Fiscal Year 2024 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*			$35,194,785				
	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 26 of 36, Line 4(d)		$115,236,039	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$115,236,039	$0	$0	$0	$0
5	Retirements	Page 26 of 36 , Line 10 ,Col (d)		$21,996,026	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$93,240,013	$93,240,013	$93,240,013	$93,240,013	$93,240,013
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$115,236,039	$0	$0	$0	$0
8	Depreciation Expense	Page 30 of 36, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$65,329,118	$65,329,118	$65,329,118	$65,329,118	$65,329,118
10	Cost of Removal	Page 26 of 36 , Line 7 ,Col (d)		$10,232,810				
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$75,561,928**	**$75,561,928**	**$75,561,928**	**$75,561,928**	**$75,561,928**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	Page 28 of 36, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/			54	311	
14	Proration Percentage		2/			14.79%	85.21%	
15	Vintage Year Tax Depreciation:							
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 14 of 36, Line 28, Column (a), Then = Line Page 14 of 36 , Column (e)		$44,142,409	$6,365,192	$870,997	$4,139,271	$7,968,373
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$44,142,409	$50,507,601	$51,378,598		
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/				$4,139,271	$12,107,643
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,473,192	$2,946,384	$435,903	$2,510,481	$2,946,384
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$1,473,192	$4,419,577	$4,855,480	$7,365,961	$10,312,345
21	Cumulative Book / Tax Timer	Columns (a) through (c): Line 17 - Line 20, Then Line 18 - Line 20		$42,669,217	$46,088,025	$46,523,118	($3,226,690)	$1,795,298
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (c)	3/				$4,855,480	$4,855,480
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$1,628,790	$6,650,778
24	Effective Tax Rate			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		$8,960,536	$9,678,485	$9,769,855	$342,046	$1,396,663
26	Add: FY 2021 Federal NOL (Generation) / Utilization	Page 26 of 36, Line 15, Col (d)	3/	($5,639,147)	($5,639,147)	($5,639,147)	$0	$0
27	Net Deferred Tax Reserve beforee Proration Adjustmer	Sum of Lines 25 through 26		$3,321,388	$4,039,338	$4,130,707	$342,046	$1,396,663
	Rate Base Calculation:							
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$75,561,928	$75,561,928	$75,561,928	$75,561,928	$75,561,928
29	Accumulated Depreciation	-Line 20		($1,473,192)	($4,419,577)	($4,855,480)	($7,365,961)	($10,312,345)
30	Deferred Tax Reserve	-Line 27		($3,321,388)	($4,039,338)	($4,130,707)	($342,046)	($1,396,663)
31	Year End Rate Base before Deferred Tax Proratioı	Sum of Lines 28 through 30		$70,767,348	$67,103,014	$66,575,741	$67,853,921	$63,852,919
	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/	$35,383,674	$68,935,181	$67,478,468	$67,478,468	$65,853,420
33	Proration Adjustment	Page 15 of 36, Line 41		$16,525	$30,816	$18,603	$18,603	$45,267
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$35,400,199	$68,965,997	$67,497,071	$67,497,071	$65,898,687
35	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/			14.79%	85.21%	
37	Return and Taxes	Cols (a),(b) and (e): L 34 * L 35; Cols (c) and (d): L 34 * L 35 * L 36	2/	$2,913,436	$5,675,902	$821,837	$4,733,172	$5,423,462
38	Book Depreciation	Line 19		$1,473,192	$2,946,384	$435,903	$2,510,481	$2,946,384
39	Revenue Requirement of Intangible Assets							
40	**Annual Revenue Requirement**	**Line 37 + Line 38 + Line 39**		**$4,386,629**	**$8,622,286**	**$1,257,740**	**$7,243,653**	**$8,369,846**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 28 of 36, Line 3, Col (e))
2/ Columns (c) and (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.
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) and (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 (b) 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
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 13 of 36, Line 3(a)		$115,236,039	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%					
3	Capital Repairs Deduction	Line 1 * Line 2		$27,063,271	MACRS basis:	Line 21, Column (a)		$88,172,768	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$115,236,039	FY Mar-2021	3.750%		$3,306,479	$44,142,409
7	Plant Additions			$0	FY Mar-2022	7.219%		$6,365,192	$50,507,601
8	Less Capital Repairs Deduction	Line 3		$27,063,271	FY Mar-2023 (Apr-May 2022)	6.677%	0.988%	$870,997	$51,378,598
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$88,172,768					
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	PPL Acquisition - May 25, 2022				
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Book Cost	Line 1, Column (a)		$115,236,039	
12	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%	Cumulative Book Depreciation	- Page 13 of 36, Line 20, Col (c)		($4,855,480)	
13	Bonus Depreciation Rate	1 * 25% * 0%		0.00%	PPL MACRS basis:	Line 11(e) + Line 12(e)		$110,380,559	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		0.00%					
15	Bonus Depreciation	Line 11 * Line 14		$0	FY Mar-2023 (Jun-Mar 2023)	3.750%		$4,139,271	$4,139,271
16					Mar-2024	7.219%		$7,968,373	$12,107,643
17	Remaining Tax Depreciation				Mar-2025	6.677%		$7,370,110	$19,477,753
18	Plant Additions	Line 1		$115,236,039	Mar-2026	6.177%		$6,818,207	$26,295,961
19	Less Capital Repairs Deduction	Line 3		$27,063,271	Mar-2027	5.713%		$6,306,041	$32,602,002
20	Less Bonus Depreciation	Line 15		$0	Mar-2028	5.285%		$5,833,613	$38,435,614
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$88,172,768	Mar-2029	4.888%		$5,395,402	$43,831,016
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2030	4.522%		$4,991,409	$48,822,425
23	Remaining Tax Depreciation	Line 21 * Line 22		$3,306,479	Mar-2031	4.462%		$4,925,181	$53,747,606
24					Mar-2032	4.461%		$4,924,077	$58,671,682
25	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$3,539,849	Mar-2033	4.462%		$4,925,181	$63,596,863
26	Cost of Removal	Page 13 of 36, Line 10		$10,232,810	Mar-2034	4.461%		$4,924,077	$68,520,939
27					Mar-2035	4.462%		$4,925,181	$73,446,120
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$44,142,409	Mar-2036	4.461%		$4,924,077	$78,370,197
29					Mar-2037	4.462%		$4,925,181	$83,295,377
30					Mar-2038	4.461%		$4,924,077	$88,219,454
31					Mar-2039	4.462%		$4,925,181	$93,144,635
32					Mar-2040	4.461%		$4,924,077	$98,068,711
33					Mar-2041	4.462%		$4,925,181	$102,993,892
34					Mar-2042	4.461%		$4,924,077	$107,917,969
35					Mar-2043	2.231%		$2,462,590	$110,380,559
36						100.00%		$110,380,559	
37									

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

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

Line No.	Deferred Tax Subject to Proration		FY22 (a)	FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation	See the corresponding Fiscal Year on Page 13 of 36, Line 19. Note there are 2 columns to sum for FY23.	$2,946,384	$2,946,384	$2,946,384	$2,946,384
2	Bonus Depreciation	Page 14 of 36, Line 20	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 13 of 36, Line 16. Note there are 2 columns to sum for FY23.	($6,365,192)	($5,010,268)	($7,968,373)	($7,370,110)
4	FY 2021 tax (gain)/loss on retirements	- Page 14 of 36, Line 25				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,418,808)	($2,063,884)	($5,021,988)	($4,423,726)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($717,950)	($433,416)	($1,054,618)	($928,982)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 14 of 36, Line 3				
9	Cost of Removal	- Page 14 of 36, 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	$0
12	Effective Tax Rate		21.00%	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	($717,950)	($433,416)	($1,054,618)	($928,982)
15	Net Operating Loss	Page 13 of 36, Line 26	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($717,950)	($433,416)	($1,054,618)	($928,982)
	Allocation of FY 2021 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,418,808)	($2,063,884)	($5,021,988)	($4,423,726)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($3,418,808)	($2,063,884)	($5,021,988)	($4,423,726)
20	Total FY 2021 Federal NOL (Utilization)	- Page 13 of 36, Line 26 / 21%	$0	$0	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0	$0
22	Allocated FY 2021 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	($717,950)	($433,416)	($1,054,618)	($928,982)

		(e)	(f)	(g)	(h)	(i)	(j)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23	FY24	FY25
26	April	30	91.78%	($54,912)	($33,149)	($80,661)	($71,052)
27	May	31	83.29%	($49,830)	($30,082)	($73,197)	($64,477)
28	June	30	75.07%	($44,913)	($27,113)	($65,974)	($58,114)
29	July	31	66.58%	($39,831)	($24,046)	($58,510)	($51,539)
30	August	31	58.08%	($34,750)	($20,978)	($51,045)	($44,964)
31	September	30	49.86%	($29,833)	($18,010)	($43,822)	($38,602)
32	October	31	41.37%	($24,751)	($14,942)	($36,358)	($32,027)
33	November	30	33.15%	($19,834)	($11,973)	($29,134)	($25,664)
34	December	31	24.66%	($14,752)	($8,906)	($21,670)	($19,089)
35	January	31	16.16%	($9,671)	($5,838)	($14,206)	($12,514)
36	February	28	8.49%	($5,081)	($3,068)	($7,464)	($6,575)
37	March	31	0.00%	$0	$0	$0	$0
38	Total	365		($328,159)	($198,105)	($482,042)	($424,617)
39	Deferred Tax Without Proration	Line 25		($717,950)	($433,416)	($1,054,618)	($928,982)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($358,975)	($216,708)	($527,309)	($464,491)
41	Proration Adjustment	Line 38 - Line 40		$30,816	$18,603	$45,267	$39,874

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
ISR Additions April 2020 through March 2021

Line No.	Month No.	Month	FY 2021 Plant Additions	In Rates		Not In Rates	Weight for Days	Weighted Average	Weight for Not in Rates
			(a)	(b)		(c) = (a) - (b)	(d)	(e) = (d) * (c)	(f)=(c)/Total(c)
1									
2	1	Apr-20	8,207,898	6,236,917		1,970,982	0.958	1,888,858	2.93%
3	2	May-20	8,207,898	6,236,917		1,970,982	0.875	1,724,609	2.93%
4	3	Jun-20	8,207,898	6,236,917		1,970,982	0.792	1,560,361	2.93%
5	4	Jul-20	8,207,898	6,236,917		1,970,982	0.708	1,396,112	2.93%
6	5	Aug-20	8,207,898	6,236,917		1,970,982	0.625	1,231,864	2.93%
7	6	Sep-20	8,207,898	-		8,207,898	0.542	4,445,945	12.19%
8	7	Oct-20	8,207,898	-		8,207,898	0.458	3,761,953	12.19%
9	8	Nov-20	8,207,898	-		8,207,898	0.375	3,077,962	12.19%
10	9	Dec-20	8,207,898	-		8,207,898	0.292	2,393,970	12.19%
11	10	Jan-21	8,207,898	-		8,207,898	0.208	1,709,979	12.19%
12	11	Feb-21	8,207,898	-		8,207,898	0.125	1,025,987	12.19%
13	12	Mar-21	8,207,898	-		8,207,898	0.042	341,996	12.19%
14		Total	$98,494,781	$31,184,583		$67,310,198		$24,559,595	100.00%
15	**Total September 2020 through March 2021**				**$**	**57,455,289**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**							**36.49%**	

Column (a)=Page 26 of 36, Line 1(c)
Column(b)=Page 26 of 36, Line 3(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
Fiscal Year 2024 Revenue Requirement on FY 2022 Actual Incremental Capital Investment

Line No.				Fiscal Year 2022 (a)	NG 4/1/22 - 5/24/2022 2023 (b)	PPL 5/25/22 - 3/31/23 2023 (c)	Fiscal Year 2024 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*	Docket 5098, P 29 of 29. Line 1(a)		$44,629,608			
	Discretionary Capital						
2	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			
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 26 of 36, Line 4(e)		$86,830,038	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$86,830,038	$0	$0	$0
5	Retirements	Page 26 of 36 , Line 10 ,Col (e)		$34,853,004	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$51,977,034	$51,977,034	$51,977,034	$51,977,034
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$86,830,038	$0	$0	$0
8	Depreciation Expense	Page 30 of 36, Line 62, Col (d)		$49,906,920	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$36,923,118	$36,923,118	$36,923,118	$36,923,118
10	Cost of Removal	Page 26 of 36 , Line 7 ,Col (e)		$7,600,505	$0	$0	$0
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$44,523,622**	**$44,523,622**	**$44,523,622**	**$44,523,622**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	Page 28 of 36, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/		54	311	
14	Proration Percentage		2/		14.79%	85.21%	
15	Vintage Year Tax Depreciation:						
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 18 of 36, Line 27, Column (a), Then = Line Page 18 of 36 , Column (e)		$41,756,966	$652,212	$3,216,218	$6,191,433
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$41,756,966	$42,409,177		
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/			$3,216,218	$9,407,651
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$821,237	$242,996	$1,399,478	$1,642,474
20	Cumulative Book Depreciation	Prior Year Line 20 + Current Year Line 19		$821,237	$1,064,233	$2,463,711	$4,106,186
21	Cumulative Book / Tax Timer	Columns (a) & (b): Line 17 - Line 20, Then Line 18 - Line 20		$40,935,729	$41,344,944	$752,506	$5,301,465
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (b)	3/			$1,064,233	$1,064,233
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22				$1,816,740	$6,365,699
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Cols (a) and (b): Line 21 * Line 24, Then Line 23 * Line 24		$8,596,503	$8,682,438	$381,515	$1,336,797
26	Add: FY 2022 Federal NOL (Generation) / Utilization	Page 26 of 36, Line 15, Col (e)	3/	($3,602,966)	($3,602,966)	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustmer	Sum of Lines 25 through 26		$4,993,537	$5,079,472	$381,515	$1,336,797
	Rate Base Calculation:						
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$44,523,622	$44,523,622	$44,523,622	$44,523,622
29	Accumulated Depreciation	-Line 20		($821,237)	($1,064,233)	($2,463,711)	($4,106,186)
30	Deferred Tax Reserve	-Line 27		($4,993,537)	($5,079,472)	($381,515)	($1,336,797)
31	Year End Rate Base before Deferred Tax Proratioı	Sum of Lines 28 through 30		$38,708,848	$38,379,917	$41,678,395	$39,080,640
	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/	$19,354,424	$40,193,622	$40,193,622	$40,379,518
33	Proration Adjustment	Page 19 of 36, Line 41		$13,239	$20,064	$20,064	$41,003
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$19,367,663	$40,213,686	$40,213,686	$40,420,521
35	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/		14.79%	85.21%	
37	Return and Taxes	Col (a) and (d): L 34 * L 35; Cols (b) through (c): L 34 * L 35 * L 36	2/	$1,593,959	$489,637	$2,819,949	$3,326,609
38	Book Depreciation	Line 19		$821,237	$242,996	$1,399,478	$1,642,474
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$2,415,196**	**$732,634**	**$4,219,427**	**$4,969,083**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 28 of 36, Line 3, Col (e))
2/ Columns (b) and (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.
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) and (c) 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 (c). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
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 17 of 36, Line 3		$86,830,038	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.67%					
3	Capital Repairs Deduction	Line 1 * Line 2		$25,762,472	NG MACRS basis:	Line 22, Column (a)		$61,067,566	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$86,830,038	FY Mar-2022	3.750%		$2,290,034	$41,756,966
7	Plant Additions			$0	FY Mar-2023 (Apr-May 2022)	7.219%	1.068%	$652,212	$42,409,177
8	Less Capital Repairs Deduction	Line 3		$25,762,472					
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$61,067,566	PPL Acquisition - May 25, 2022				
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Book Cost	Line 1, Column (a)		$86,830,038	
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Cumulative Book Depreciation	- Page 17 of 36, Line 20, Col (b)		($1,064,233)	
12	Bonus Depreciation Rate	at 0%		0.00%	PPL MACRS basis:	Line 10(e) + Line 11(e)		$85,765,805	
13	Total Bonus Depreciation Rate	Line 12		0.00%					
14	Bonus Depreciation	Line 11 * Line 13		$0	FY Mar-2023 (Jun-Mar 2023)	3.750%		$3,216,218	$3,216,218
15					Mar-2024	7.219%		$6,191,433	$9,407,651
16	Remaining Tax Depreciation				Mar-2025	6.677%		$5,726,583	$15,134,234
17	Plant Additions	Line 1		$86,830,038	Mar-2026	6.177%		$5,297,754	$20,431,988
18	Less Capital Repairs Deduction	Line 3		$25,762,472	Mar-2027	5.713%		$4,899,800	$25,331,788
19	Less Bonus Depreciation	Line 14		$0	Mar-2028	5.285%		$4,532,723	$29,864,511
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$61,067,566	Mar-2029	4.888%		$4,192,233	$34,056,743
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2030	4.522%		$3,878,330	$37,935,073
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,290,034	Mar-2031	4.462%		$3,826,870	$41,761,943
23					Mar-2032	4.461%		$3,826,013	$45,587,956
24	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$6,103,955	Mar-2033	4.462%		$3,826,870	$49,414,826
25	Cost of Removal	Page 17 of 36, Line 10		$7,600,505	Mar-2034	4.461%		$3,826,013	$53,240,839
26					Mar-2035	4.462%		$3,826,870	$57,067,709
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$41,756,966	Mar-2036	4.461%		$3,826,013	$60,893,721
28					Mar-2037	4.462%		$3,826,870	$64,720,592
29					Mar-2038	4.461%		$3,826,013	$68,546,604
30					Mar-2039	4.462%		$3,826,870	$72,373,474
31					Mar-2040	4.461%		$3,826,013	$76,199,487
32					Mar-2041	4.462%		$3,826,870	$80,026,357
33					Mar-2042	4.461%		$3,826,013	$83,852,370
34					Mar-2043	2.231%		$1,913,435	$85,765,805
35						100.000%		$85,765,805	
36									

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

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

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation	See the corresponding Fiscal Year on Page 17 of 36, Line 19. Note there are 2 columns to sum for FY23.	$821,237	$1,642,474	$1,642,474	$1,642,474
2	Bonus Depreciation	Page 14 of 36, Line 20	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 18 of 36, Line 22, column (a), thereafter, see the corresponding Fiscal Year on Page 17 of 36, Line 16. Note there are 2 columns to sum for FY23.	($2,290,034)	($3,868,429)	($6,191,433)	($5,726,583)
4	FY 2022 tax (gain)/loss on retirements	- Page 18 of 36, Line 24				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,468,797)	($2,225,955)	($4,548,959)	($4,084,109)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($308,447)	($467,451)	($955,281)	($857,663)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 18 of 36, Line 3	($25,762,472)			
9	Cost of Removal	- Page 18 of 36, Line 25	($7,600,505)			
10	Book/Tax Depreciation Timing Difference at 3/31/2022					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($33,362,977)	$0	$0	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($7,006,225)	$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($7,314,672)	($467,451)	($955,281)	($857,663)
15	Net Operating Loss	Page 17 of 36, Line 26	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($7,314,672)	($467,451)	($955,281)	($857,663)
	Allocation of FY 2022 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,468,797)	($2,225,955)	($4,548,959)	($4,084,109)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($33,362,977)	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($34,831,773)	($2,225,955)	($4,548,959)	($4,084,109)
20	Total FY 2022 Federal NOL (Utilization)	- Page 17 of 36, Line 26 / 21%	$0	$0	$0	$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0	$0
22	Allocated FY 2022 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	($308,447)	($467,451)	($955,281)	($857,663)

Line No.	**Proration Calculation**	Number of Days in Month (e)	Proration Percentage (f)	FY22 (g)	FY23 (h)	FY24 (i)	FY25 (j)
26	April	30	91.78%	($23,591)	($35,752)	($73,064)	($65,597)
27	May	31	83.29%	($21,408)	($32,444)	($66,303)	($59,527)
28	June	30	75.07%	($19,296)	($29,242)	($59,760)	($53,653)
29	July	31	66.58%	($17,112)	($25,934)	($52,998)	($47,583)
30	August	31	58.08%	($14,929)	($22,625)	($46,237)	($41,512)
31	September	30	49.86%	($12,817)	($19,424)	($39,694)	($35,638)
32	October	31	41.37%	($10,634)	($16,115)	($32,933)	($29,568)
33	November	30	33.15%	($8,521)	($12,914)	($26,390)	($23,693)
34	December	31	24.66%	($6,338)	($9,605)	($19,629)	($17,623)
35	January	31	16.16%	($4,155)	($6,297)	($12,868)	($11,553)
36	February	28	8.49%	($2,183)	($3,308)	($6,761)	($6,070)
37	March	31	0.00%	$0	$0	$0	$0
38	Total	365		($140,984)	($213,661)	($436,638)	($392,018)
39	Deferred Tax Without Proration	Line 25		($308,447)	($467,451)	($955,281)	($857,663)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($154,224)	($233,725)	($477,641)	($428,831)
41	Proration Adjustment	Line 38 - Line 40		$13,239	$20,064	$41,003	$36,813

Column Notes:

(f) Sum of remaining days in the year (Col (e)) ÷ 365

(g) through (h) Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2024 Revenue Requirement on FY 2023 Actual Incremental Capital Investment

Line No.				NG 4/1/22 - 5/24/2022 2023 (a)	PPL 5/25/22 - 3/31/23 2023 (b)	Fiscal Year 2024 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*	Docket 5209, P 33 of 33. Line 1	2/	$6,166,640	$35,515,280	
	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	2/	$7,632,024	$43,954,804	
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$13,798,664	$79,470,084	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,798,664	$79,470,084	
5	Retirements	Company's Record	2/	$2,633,153	$15,165,012	
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$11,165,511	$64,305,072	$75,470,583
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$13,798,664	$79,470,084	$0
8	Depreciation Expense	Page 30 of 36, Line 62, Col (d)	2/	$7,383,490	$42,523,431	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$6,415,174	$36,946,653	$43,361,828
10	Cost of Removal	Company's Record	2/	$1,142,377	$6,579,244	
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$7,557,551**	**$43,525,897**	**$51,083,449**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	Page 28 of 36, Line 3, Col (e)	1/	3.16%	3.16%	3.16%
13	Proration Percentage					
14	Vintage Year Tax Depreciation:					
15	Tax Depreciation and Year 1 Basis Adjustments	Col (a) = Page 21 of 36, Column (a), Line 27; Col (b) = Page 21 of 36, Col (b), Lines 18,24,25 + Col (e), Line 15, Then remaining years from Page 21 of 36, Col (e)		$6,181,052	$36,109,117	$5,558,030
16	Cumulative Tax Depreciation-NG	Col (a) = Line 15; then 0	3/	$6,181,052		
17	Cumulative Tax Depreciation-PPL	Col (b) = Line 15; then = Prior Year Line 17 + Current Year Line 15	3/		$36,109,117	$41,667,147
18	Book Depreciation	Year 1 (Columns (a) and (b)) = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$176,415	$1,016,020	$2,384,870
19	Cumulative Book Depreciation	Year 1 = Line 18; then = Prior Year Line 19 + Current Year Line 18		$176,415	$1,192,435	$3,577,306
20	Book / Tax Timer	Line 15 - Line 18		$6,004,637	$35,093,097	$3,173,160
21	Cumulative Book / Tax Timer -NG	Col (a) = Line 20, Column (a), Then = 0	3/	$6,004,637		
22	Cumulative Book / Tax Timer - PPL	Col (a) = 0; Col (b) = Line 20, Column (b); then = Prior Year Line 22 + Current Year Line 20	3/		$35,093,097	$38,266,257
23	Cumulative Book / Tax Timer - Total	Line 21 + Line 22		$6,004,637	$35,093,097	$38,266,257
24	Effective Tax Rate			21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Line 23 × Line 24		$1,260,974	$7,369,550	$8,035,914
26	Add: FY 2023 Federal NOL (Generation) / Utilization	Page 26 of 36 , Line 13 ,Col (f)	3/	$23,627,830		
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$24,888,804	$7,369,550	$8,035,914
	Rate Base Calculation:					
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$7,557,551	$43,525,897	$51,083,449
29	Accumulated Depreciation	Year 1 (Cols (a) and (b)) = -Line 18; Then = -Line 19		($176,415)	($1,016,020)	($3,577,306)
30	Deferred Tax Reserve	-Line 27		($24,888,804)	($7,369,550)	($8,035,914)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		($17,507,668)	$35,140,327	$39,470,229
	Revenue Requirement Calculation:					
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 (Cols (a) and (b)) = Current Year, Line 31 * 50%; Then = (Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	($8,753,834)	$17,570,163	$28,551,444
33	Proration Adjustment	Page 22 of 36, Line 41	2/	$120,555	$33,147	$28,602
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		($8,633,279)	$17,603,310	$28,580,046
35	Pre-Tax ROR	Page 34 of 36, Line 35		8.23%	8.23%	8.23%
36	Proration	Line 13				
37	Return and Taxes	Line 34 x Line 35		($710,519)	$1,448,752	$2,352,138
38	Book Depreciation	Line 18		$176,415	$1,016,020	$2,384,870
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**($534,104)**	**$2,464,773**	**$4,737,008**
40	Sum of Columns (a) and (b) equal Docket No. 5209 FY 2023 Electric ISR Reconciliation, Page 1, Line 10(b) or Page 20, Line 39(a) and 39(b)			$390,169	$2,436,254	
41	2023 Tax True-Up including impact on DG Adjustments made through FY 2023 reconciliation filing			($924,273)	$28,519	
42	FY 2023 Tax True-up as reflected on Line 46			($926,258)	$17,115	
43	FY 2023 DG Adjustment as reflected on Page 36, Column e, Line 22	Line 41 - Line 42		$1,985	$11,404	
	Check:					
44	FY 2023 revenue requirement from Line 40 after tax adjustments			($536,088)	$2,453,369	
45	FY 2023 revenue requirement from Line 40 before tax adjustments			$390,169	$2,436,254	
46	FY 2023 Tax True-up			($926,258)	$17,115	

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 28 of 36, Line 3, Col (e))

2/ Columns (a) and (b) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.

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 (c) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 32, Columns (a) and (b) and the end of the fiscal year on Line 30, Column (c). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2023-NG Incremental Capital Investments

Line No.				NG Apr 1-May 24, 2022 Fiscal Year 2023 (a)	PPL May 25-Mar 31, 2023 Fiscal Year 2023 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 20 of 36, Line 3, Columns (a) through (c)		$13,798,664	$79,470,084
2	Capital Repairs Deduction Rate	Per Tax Department	1/	20.26%	20.26%
3	Capital Repairs Deduction	Line 1 * Line 2		$2,795,609	$16,100,639
4					
5	Bonus Depreciation				
6	Plant Additions	Line 1		$13,798,664	$79,470,084
7	Plant Additions			$0	$0
8	Less Capital Repairs Deduction	Line 3		$2,795,609	$16,100,639
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$11,003,055	$63,369,445
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	$0
12	Bonus Depreciation Rate	at 0%		0.00%	0.00%
13	Total Bonus Depreciation Rate	Line 12		0.00%	0.00%
14	Bonus Depreciation	Line 11 * Line 13		$0	$0
15					
16	Remaining Tax Depreciation				
17	Plant Additions	Line 1		$13,798,664	$79,470,084
18	Less Capital Repairs Deduction	Line 3		$2,795,609	$16,100,639
19	Less Bonus Depreciation	Line 14		$0	$0
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$11,003,055	$63,369,445
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	3.750%
22	Remaining Tax Depreciation	Line 20 * Line 21		$412,615	$2,376,354
23					
24	FY23 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$1,830,452	$10,542,045
25	Cost of Removal	Page 20 of 36, Line 10		$1,142,377	$6,579,244
26					
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$6,181,052	$35,598,283
28					
29	Reconcilation of MACRS Tax Depreciation:				
30	Apr 1 -May 24, 2022 Plant Additions	Line 1, Column (a)			$13,798,664
31	Cumulative Book Depreciaiton through May 24, 2022	Page 20 of 36, Line 18, Col (a)			($176,415)
32	2023 Plant Additions (Net Book) through Acquisition	Line 30 + Line 31			$13,622,249
33	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%
34	Tax Depreciation	Line 32 * Line 33			$510,833
35					
36	MACRS Basis in May 25-Mar 2023 Plant Additions	Line 20, Column (b)			$63,369,445
37	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%
38	Tax Depreciation	Line 36 * Line 37			$2,376,353
39					
40	Total MACRS Tax Depreciation	Sum of Lines 34, 38, Column (b)			$2,887,187
41					

20 Year MACRS Depreciation

(c)	(d)	(e)	(f)
MACRS basis:	Line 20, Column (a)	$11,003,055	
		Annual	Cumulative
Fiscal Year		MACRS	Tax Depr
FY Mar-2023 (Apr-May 2022)	3.750%	$412,615	$6,181,052
PPL Acquisition - May 25, 2022			
Book Cost	Line 1, Column (a)	$13,798,664	
Cumulative Book Depreciation	- Page 20 of 36, Line 18, Col (a)	($176,415)	
MACRS basis from Acquisition:	Line 9(e) + Line 10(e)	$13,622,249	
MACRS basis (Jun-Mar 2023)	Line 20, Column (b)	$63,369,445	
Total MACRS Basis in 2022	Line 11(e) + Line 12(e)	$76,991,694	
FY Mar-2023 (Jun-Mar 2023)	3.750%	$2,887,189	$36,109,117
Mar 2024	7.219%	$5,558,030	$41,667,147
Mar 2025	6.677%	$5,140,735	$46,807,883
Mar 2026	6.177%	$4,755,777	$51,563,660
Mar 2027	5.713%	$4,398,535	$55,962,195
Mar 2028	5.285%	$4,069,011	$60,031,206
Mar 2029	4.888%	$3,763,354	$63,794,560
Mar 2030	4.522%	$3,481,564	$67,276,125
Mar 2031	4.462%	$3,435,369	$70,711,494
Mar 2032	4.461%	$3,434,599	$74,146,094
Mar 2033	4.462%	$3,435,369	$77,581,463
Mar 2034	4.461%	$3,434,599	$81,016,062
Mar 2035	4.462%	$3,435,369	$84,451,432
Mar 2036	4.461%	$3,434,599	$87,886,031
Mar 2037	4.462%	$3,435,369	$91,321,401
Mar 2038	4.461%	$3,434,599	$94,756,000
Mar 2039	4.462%	$3,435,369	$98,191,370
Mar 2040	4.461%	$3,434,599	$101,625,969
Mar 2041	4.462%	$3,435,369	$105,061,338
Mar 2042	4.461%	$3,434,599	$108,495,938
Mar 2043	2.231%	$1,717,685	$110,213,623
	100.00%	$76,991,694	

42 1/ Capital Repairs percentage is based on the actual results of National Grid's short period FY2023 tax return and PPL's short period CY2022 tax return, which covers the period from April 2022 through December 2022. When PPL files it calendar year 2023 consolidated tax return in October of 2024, the tax repairs percentage will be updated to reflect the January through March 2023 actual tax repairs.

43 2/ FY 2023 tax loss on retirements is based on actual tax losses from April through December 2022. When PPL files it calendar year 2023 consolidated tax return in October of 2024, a portion of the tax gain/loss on retirements will be allocated to the January through March 2023 period to finalize this fiscal year.

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

Line No.	**Deferred Tax Subject to Proration**		NG 4/1/22 - 5/24/2022 FY23 (a)	PPL 5/25/22 - 3/31/23 FY23 (b)	FY24 (c)	FY25 (d)
1	Book Depreciation	See the corresponding Fiscal Year on Page 20 of 36, Line 18	$176,415	$1,016,020	$2,384,870	$2,384,870
2	Bonus Depreciation	- Page 21 of 36, Line 14	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 21 of 36, column (e), Lines 6,18,19,20	($412,615)	($2,887,189)	($5,558,030)	($5,140,735)
4	FY 2023 tax (gain)/loss on retirements	- Page 21 of 36, Line 24	($1,830,452)	($10,542,045)		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,066,651)	($12,413,214)	($3,173,160)	($2,755,865)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($433,997)	($2,606,775)	($666,364)	($578,732)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 21 of 36, Line 3	($2,795,609)	($16,100,639)		
9	Cost of Removal	- Page 21 of 36, Line 25	($1,142,377)	($6,579,244)		
10	Book/Tax Depreciation Timing Difference at 3/31/2023					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($3,937,986)	($22,679,883)	$0	$0
12	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($826,977)	($4,762,775)	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($1,260,974)	($7,369,550)	($666,364)	($578,732)
15	Net Operating Loss	- Page 20 of 36, Line 26	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($1,260,974)	($7,369,550)	($666,364)	($578,732)
	Allocation of FY 2023 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($2,066,651)	($12,413,214)	($3,173,160)	($2,755,865)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($3,937,986)	($22,679,883)	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($6,004,637)	($35,093,097)	($3,173,160)	($2,755,865)
20	Total FY 2023 Federal NOL (Utilization)	- Page 20 of 36, 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	($433,997)	($2,606,775)	($666,364)	($578,732)

Line No.	**Proration Calculation**	(e) Number of Days in Month	(f) Proration Percentage	(g) FY23	(h) FY23	(i) FY24	(j) FY25
26	April	30	91.78%	($96,444)		($50,966)	($44,264)
27	May	31	83.29%	$0	($231,646)	($46,250)	($40,168)
28	June	30	75.07%		($208,786)	($41,686)	($36,204)
29	July	31	66.58%		($185,164)	($36,969)	($32,108)
30	August	31	58.08%		($161,542)	($32,253)	($28,012)
31	September	30	49.86%		($138,683)	($27,689)	($24,048)
32	October	31	41.37%		($115,061)	($22,973)	($19,952)
33	November	30	33.15%		($92,201)	($18,409)	($15,988)
34	December	31	24.66%		($68,579)	($13,692)	($11,892)
35	January	31	16.16%		($44,958)	($8,976)	($7,796)
36	February	28	8.49%		($23,622)	($4,716)	($4,096)
37	March	31	0.00%		$0	$0	$0
38	Total	365		($96,444)	($1,270,241)	($304,580)	($264,525)
39	Deferred Tax Without Proration	Line 25		($433,997)	($2,606,775)	($666,364)	($578,732)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($216,998)	($1,303,387)	($333,182)	($289,366)
41	Proration Adjustment	Line 38 - Line 40		$120,555	$33,147	$28,602	$24,841

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 25 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2024 Revenue Requirement on FY 2024 Actual Incremental Capital Investment

Line No.				Fiscal Year 2024 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	P 35 of 36. Line 1		$45,486,999
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	P 35 of 36. Line 13		$51,836,809
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$97,323,808
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$97,323,808
5	Retirements	Company's Record		$20,913,590
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$76,410,218
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$97,323,808
8	Depreciation Expense	Page 30 of 36, Line 62, Col (d)		$49,906,920
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$47,416,888
10	Cost of Removal	Company's Record		$9,267,248
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$56,684,136**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	Page 28 of 36, Line 3, Col (e)	1/	3.16%
13	Proration Percentage			
14	Vintage Year Tax Depreciation:			
15	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 24 of 36, Line 27, Column (a), Then = Line Page 24 of 36 , Column (d)		$72,624,283
16	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$72,624,283
17	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,207,281
18	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,207,281
19	Cumulative Book / Tax Timer	Line 16 - Line 18		$71,417,002
20	Effective Tax Rate			21.00%
21	Deferred Tax Reserve	Line 19 * Line 20		$14,997,570
22	Add: CY 2024 Federal NOL (Generation) / Utilization	Company's Record		$0
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 21 through 22		$14,997,570
	Rate Base Calculation:			
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$56,684,136
25	Accumulated Depreciation	-Line 18		($1,207,281)
26	Deferred Tax Reserve	-Line 23		($14,997,570)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$40,479,284
	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		$20,239,642
29	Proration Adjustment	Page 25 of 36, Line 41		$168,684
30	Average ISR Rate Base after Deferred Tax Proration	Line 29 + Line 30		$20,408,325
31	Pre-Tax ROR	Page 34 of 36, Line 33		8.23%
32	Proration	Line 13		100.00%
33	Return and Taxes	Year 1 = Lines 30 * 31 * 32		$1,679,605
34	Book Depreciation	Line 17		$1,207,281
35	**Annual Revenue Requirement**	**Line 33 + Line 34**		**$2,886,887**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 28 of 36, Line 3, Col (e))

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2024 Incremental Capital Investments

Line No.				Fiscal Year 2024 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 23 of 36, Line 3		$97,323,808	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	44.63%				
3	Capital Repairs Deduction	Line 1 * Line 2		$43,435,616	MACRS basis:	Line 20	$53,888,192	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$97,323,808	Mar-2024	3.750%	$2,020,807	$72,624,283
7	Plant Additions			$0	Mar-2025	7.219%	$3,890,189	$76,514,472
8	Less Capital Repairs Deduction	Line 3		$43,435,616	Mar-2026	6.677%	$3,598,115	$80,112,586
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$53,888,192	Mar-2027	6.177%	$3,328,674	$83,441,260
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Mar-2028	5.713%	$3,078,632	$86,519,892
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Mar-2029	5.285%	$2,847,991	$89,367,883
12	Bonus Depreciation Rate	at 0%		0.00%	Mar-2030	4.888%	$2,634,055	$92,001,938
13	Total Bonus Depreciation Rate	Line 12		0.00%	Mar-2031	4.522%	$2,436,824	$94,438,762
14	Bonus Depreciation	Line 11 * Line 13		$0	Mar-2032	4.462%	$2,404,491	$96,843,253
15					Mar-2033	4.461%	$2,403,952	$99,247,205
16	Remaining Tax Depreciation				Mar-2034	4.462%	$2,404,491	$101,651,697
17	Plant Additions	Line 1		$97,323,808	Mar-2035	4.461%	$2,403,952	$104,055,649
18	Less Capital Repairs Deduction	Line 3		$43,435,616	Mar-2036	4.462%	$2,404,491	$106,460,140
19	Less Bonus Depreciation	Line 14		$0	Mar-2037	4.461%	$2,403,952	$108,864,092
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$53,888,192	Mar-2038	4.462%	$2,404,491	$111,268,583
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2039	4.461%	$2,403,952	$113,672,535
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,020,807	Mar-2040	4.462%	$2,404,491	$116,077,027
23					Mar-2041	4.461%	$2,403,952	$118,480,979
24	FY24 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$17,900,612	Mar-2042	4.462%	$2,404,491	$120,885,470
25	Cost of Removal	Page 23 of 36, Line 10		$9,267,248	Mar-2043	4.461%	$2,403,952	$123,289,422
26					Mar-2044	2.231%	$1,202,246	$124,491,668
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$72,624,283		100.00%	$53,888,192	

1/ Per Tax Department
2/ Per Tax Department

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

Line No.	Deferred Tax Subject to Proration		FY24 (a)	FY25 (b)
1	Book Depreciation	Page 23 of 36, Line 17	$1,207,281	$2,414,563
2	Bonus Depreciation	- Page 24 of 36, Line 14	$0	
3	Remaining MACRS Tax Depreciation	- Page 24 of 36, column (d), Lines 6 and 7	($2,020,807)	($3,890,189)
4	Plan Year 2024 tax (gain)/loss on retirements	- Page 24 of 36, Line 24	($17,900,612)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($18,714,138)	($1,475,626)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($3,929,969)	($309,881)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 24 of 36, Line 3	($43,435,616)	
9	Cost of Removal	- Page 24 of 36, Line 25	($9,267,248)	
10	Book/Tax Depreciation Timing Difference at 3/31/2024			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($52,702,864)	$0
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($11,067,601)	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($14,997,570)	($309,881)
15	Net Operating Loss	Page 23 of 36, Line 22	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($14,997,570)	($309,881)
	Allocation of Plan Year 2024 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($18,714,138)	($1,475,626)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($52,702,864)	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($71,417,002)	($1,475,626)
20	Total Plan Year 2024 Federal NOL (Utilization)	- Page 23 of 36, Line 22 / 21%	$0	$0
21	Allocated Plan Year 2024 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated Plan Year 2024 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	($3,929,969)	($309,881)

Line No.	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) FY24	(f) FY25
26	April	30	91.78%	($300,580)	($23,701)
27	May	31	83.29%	($272,765)	($21,508)
28	June	30	75.07%	($245,847)	($19,385)
29	July	31	66.58%	($218,033)	($17,192)
30	August	31	58.08%	($190,218)	($14,999)
31	September	30	49.86%	($163,300)	($12,876)
32	October	31	41.37%	($135,485)	($10,683)
33	November	30	33.15%	($108,568)	($8,561)
34	December	31	24.66%	($80,753)	($6,367)
35	January	31	16.16%	($52,938)	($4,174)
36	February	28	8.49%	($27,815)	($2,193)
37	March	31	0.00%	$0	$0
38	Total	365		($1,796,301)	($141,640)
39	Deferred Tax Without Proration	Line 25		($3,929,969)	($309,881)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($1,964,984)	($154,941)
41	Proration Adjustment	Line 38 - Line 40		$168,684	$13,301

Column Notes:

(d) Sum of remaining days in the Apr 1-Dec 31 period (Col (c)) ÷ 275

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
FY 2018 - 2024 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	$91,750,966	$110,106,650	$98,494,781	$115,236,039	$86,830,038	$93,268,748
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	$16,907,966	$31,803,024	$67,310,198	$115,236,039	$86,830,038	$93,268,748
	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	$9,952,716	$8,209,732	$14,770,644	$10,438,210	$7,686,088	$7,721,621
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	$1,693,009	$361,723	$11,332,719	$10,232,810	$7,600,505	$7,721,621
	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	$17,798,165
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	$17,798,165
	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	$730,905	$35,805,866
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	$248,590	$12,178,036
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 27 of 36, Line 12	($2,998,499)	$991,622	$0	$1,125,232	$482,315	$23,627,830
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)	($3,602,966)	$23,627,830

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliatior
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			Test Year July 2016 - June 2017					Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020	12 Mths Aug 31 2021	12 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		$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	$55,528
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						$981,448						$981,448
10	TOTAL Plant DIT Provision	$4,261,399	$6,352,031	$11,261,635	$21,112,654	$26,345,306	$27,282,971	$14,819,666	$5,274,131	$4,062,021	$9,302,963	$5,545,830	$937,665
11	Distribution-related NOL							$2,998,499	($991,622)	$0	($1,125,232)	($482,315)	23,722,289.55
12	Lesser of Distribution-related NOL or DIT Provision							$2,998,499	($991,622)	$0	($1,125,232)	($482,315)	$937,665
13	Total NOL												35,805,866.00
14	NOL recovered in transmission rates												12,083,576.45
15	Distribution-related NOL												23,722,289.55

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(g)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 3
1(h)	RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 7
1(i)	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 & 5
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)~(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.25(a)+L.27(a); P.2, L.25(b)+L.27(b); P.2, L.25(c)+L.27(c); P.2, L.25(d)+L.27(d); P.2, L.25(e)+L.27(e); P.2, L.25(f)+L.27(f))
5(b)~(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.5, L.25(a)+P.8, L.27(c); P.5, L.25(b)+P.8, L.27(f); P.5, L.25(c)+P.8, L.27(i); P.5, L.25(d)+P.8, L.27(l); P.5, L.25(e)+P.8, L.27(o))
6(c)~(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.10, L.25(a); P.10, L.25(b); P.10, L.25(c); P.10, L.25(d))
7(d)~(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.13, L.25(a); P.13, L.25(b); P.13, L.25(c))
8(e)~(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.17, L.25(a)+P.17, L.25(b))
9(f)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.20, L.25(a))
4(g) -9(l)	Year over year change in cumulative DIT shown in Cols (a) through (f)
10	Sum of Lines 3 through 9
11	Page 26 of 36, 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 Syste	$ 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 Adjustment		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 ~ FY17 10.27%

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		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 28 of 36, Line 66 (c)				($1,435,572)
69		Plus: Comm Equipment Depreciation		Page 28 of 36, 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 28 of 36, Line 66 (c)				($1,435,572)
76		Plus: Comm Equipment Depreciation		Page 28 of 36, 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
Fiscal Year Year 2023 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	$98,495	$9,017	$107,511		($14,649)		$1,790,725
7	Accumulated Depr	$705,047				$54,178	($14,649)	($14,771)	$729,804
8	Net Plant	$992,816							$1,060,921
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	$115,236	$3,274	$118,510		($22,589)		$1,886,646
12	Accumulated Depr	$729,804				$57,246	($22,589)	($11,374)	$753,088
13	Net Plant	$1,060,921							$1,133,559
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	$86,830	$13,092	$99,923		($35,100)		$1,951,469
17	Accumulated Depr	$753,088				$59,937	($35,100)	($7,686)	$770,238
18	Net Plant	$1,133,559							$1,181,231
19	Property Tax Expense	$33,333							$33,955
20	Effective Prop Tax Rate	2.94%							2.88%
	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	$1,951,469	$93,269	$11,413	$104,682		($17,798)		$2,038,353
22	Accumulated Depr	$770,238				$63,592	($17,798)	($8,431)	$807,601
23	Net Plant	$1,181,231							$1,230,752
24	Property Tax Expense	$33,955							$34,532
25	Effective Prop Tax Rate	2.87%							2.81%
	Effective Tax Rate Calculation	End of FY 2023	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2024
26	Plant In Service	$2,038,353	$97,324	$6,933	$104,257		($35,642)		$2,106,968
27	Accumulated Depr	$807,601				$64,348	($35,642)	($9,267)	$827,039
28	Net Plant	$1,230,752							$1,279,929
29	Property Tax Expense	$34,532							$40,092
30	Effective Prop Tax Rate	2.81%							3.13%
	Effective Tax Rate Calculation	End of FY 2024	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2025
31	Plant In Service	$2,106,968	$100,138	$11,413	$111,551		($25,441)		$2,193,078
32	Accumulated Depr	$827,039				$65,064	($25,441)	($19,320)	$847,342
33	Net Plant	$1,279,929							$1,345,735
34	Property Tax Expense	$40,092							$37,761
35	Effective Prop Tax Rate	3.13%							2.81%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2023 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			$35,264	
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)			($980)	
39	COR		$9,980			$7,949			$362	
40	Net Plant Additions		$58,291			$74,532			$34,645	
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	$17,502	1.88%	$330
49	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	3.29%	$1,256	$37,040	1.35%	$499	$34,645	1.88%	$652
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			$703

		(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		$67,310			$115,236			$86,830	
54	Book Depreciation: base allowance on ISR eligible plant		$0			$0			($29,112)	
55	Book Depreciation: current year ISR additions		($1,000)			($1,473)			($821)	
56	COR		$11,333			$10,233			$7,601	
57	Net Plant Additions		$77,643			$123,996			$64,497	
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%			2.88%		
61	RY Effective Tax Rate	3.38%	-0.31%		3.58%	-0.64%		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%	($2,825)	$853,576	* -0.64%	($5,427)	$833,223	* -0.79%	($6,574)
64	Non-ISR plant times rate difference	($2,269)	-0.31%	$7	($4,269)	* -0.64%	$27	($6,269)	* -0.79%	$49
65	FY 2018 Net Incremental times rate difference	$16,802	3.07%	$516	$16,102	* 2.94%	$474	$15,402	* 2.88%	$443
66	FY 2019 Net Incremental times rate difference	$32,809	3.07%	$1,007	$30,973	* 2.94%	$911	$29,137	* 2.88%	$838
67	FY 2020 Net Incremental times rate difference	$77,643	3.07%	$2,384	$75,643	* 2.94%	$2,225	$73,643	* 2.88%	$2,117
68	FY 2021 Net Incremental times rate difference				$123,996	* 2.94%	$3,647	$121,049	* 2.88%	$3,480
69	FY 2022 Net Adds times rate differenc							$64,497	* 2.88%	$1,854
70	Total ISR Property Tax Recovery			$1,090			$1,856			$2,208

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 3 (continued)
(000s)

		(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)
		Cumulative Increm. ISR Prop. Tax for FY2023			Cumulative Increm. ISR Prop. Tax for FY2024			Cumulative Increm. ISR Prop. Tax for FY2025		
71	Incremental ISR Additions		$93,269			$97,324			$100,138	
72	Book Depreciation: base allowance on ISR eligible plant		($49,907)			($49,907)			($49,907)	
73	Book Depreciation: current year ISR additions		($1,192)			($1,207)			($45,344)	
74	COR		$7,722			$9,267			$19,320	
75	Net Plant Additions		$49,891			$55,477			$24,206	
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	2.81%			3.13%			2.81%		
79	RY Effective Tax Rate	3.66%	-0.86%		3.66%	-0.53%		3.66%	-0.86%	
80	RY Effective Tax Rate 7 mos for FY 2019									
81	RY Net Plant times Rate Difference	$833,223	* -0.86%	($7,149)	$833,223	* -0.53%	($4,433)	$833,223	* -0.86%	($7,149)
82	Non-ISR plant times rate difference	($8,269)	* -0.86%	$71	($10,269)	* -0.53%	$55	($12,269)	* -0.86%	$105
83	FY 2018 Net Incremental times rate difference	$14,702	* 2.81%	$413	$14,002	* 3.13%	$439	$13,302	* 2.81%	$373
84	FY 2019 Net Incremental times rate difference	$27,302	* 2.81%	$766	$25,466	* 3.13%	$798	$23,630	* 2.81%	$663
85	FY 2020 Net Incremental times rate difference	$71,643	* 2.81%	$2,010	$69,642	* 3.13%	$2,181	$67,642	* 2.81%	$1,898
86	FY 2021 Net Incremental times rate difference	$118,103	* 2.81%	$3,314	$115,157	* 3.13%	$3,607	$112,210	* 2.81%	$3,149
87	FY 2022 Net Incremental times rate difference	$62,854	* 2.81%	$1,764	$61,212	* 3.13%	$1,917	$59,570	* 2.81%	$1,672
88	FY 2023 Net Incremental times rate difference	$49,891	* 2.81%	$1,400	$47,506	* 3.13%	$1,488	$45,121	* 2.81%	$1,266
89	FY 2024 Net Incremental times rate difference				$55,477	* 3.13%	$1,738	$53,062	* 2.81%	$1,489
90	FY 2025 Net Incremental times rate difference							$24,206	* 2.81%	$679
91	Total ISR Property Tax Recovery			$2,588			$7,789			$4,145

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)) +((Page 2 of 36, L 6(a) + Page 5 of 36, L 6(a)+Page 10 of 36, L(a)+, L6(a)) × 0.0316+Page 8 of 3633(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 20 of 36, 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 13 of 36, 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 20 of 36, Line 3(a) through 3(c) / 100(
72(t)	Page 20 of 36, Line 8(a) through 8(c) / 1000
73(t)	Page 20 of 36, Line 19(a) through 19(c) /1000
74(t)	Page 20 of 36, 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 36, Line 19(i) / 1000
84(s)	=66(p) - (Page 5 of 36, Line 19(e) + Page 8 of 36, Line 33(o))/1000
85(s)	=67(p) - (Page 10 of 36, Line 19(d) through 19(f) / 1000
86(s)	=68(p) - (Page 13 of 36, Line 19(c) through 19(e) / 1000
87(s)	=69(p) - (Page 17 of 36, 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)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2024 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
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
FY 2024 Incremental Capital Investment

Line No.			Fiscal Year 2024 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in FY 2024 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	Fiscal Year 2024 Proposed Non-Discretionary Capital Additions	Attachment NAG-1, Table 1, Col (b), Line 1	**$45,486,999**	**$0**	$45,486,999
	Discretionary Capital				
2	Cumulative FY 2023 Discretionary Capital ADDITIONS	Docket 4915 + Docket 4995 + Docket 5098 + Docket 5209	$564,708,179		
3	FY 2024 Discretionary Capital ADDITIONS	Attachment NAG-1, Table 1, Col (b), Line 2	$51,836,809		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$616,544,988		
5	Cumulative FY 2023 Discretionary Capital SPENDING	Docket 4915 + Docket 4995 + Docket 5098 + Docket 5209	$614,292,033		
6	FY 2024 Discretionary Capital SPENDING	Attachment NAG-1, Table 1, Col (b), Line 8	$68,608,942		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$682,900,975		
8	Cumulative FY 2023 Approved Discretionary Capital SPENDING	Docket 4915 + Docket 4995 + Docket 5098 + Docket 5209	$615,807,536		
9	FY 2024 Approved Discretionary Capital SPENDING	Attachment NAG-1, Table 1, Col (b), Line 8	$68,608,942		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$684,416,478		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$616,544,988		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Docket No. 5209 -ISR Plan Reconciliation	$564,708,179		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$51,836,809**	**$0**	**$51,836,809**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$97,323,808**	**$0**	**$97,323,808**
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			**$97,323,808**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Revenue Requirement Adjustment for DG Project Review

Line No.		Actual-Revised Fiscal Year 2018 (a)	Actual-Revised Fiscal Year 2019 (b)	Actual-Revised Fiscal Year 2020 (c)	Actual-Revised Fiscal Year 2021 (d)	Actual-Revised Fiscal Year 2022 (e)	Actual-Revised Fiscal Year 2023 (e)
	Capital Investment:						
1	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,081,472	$2,103,770	$2,026,221	$1,972,340	$1,919,087	$1,845,740
2	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		$1,523,254	$4,337,891	$4,171,209	$4,017,782	$4,048,255
3	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			$2,362,055	$5,625,336	$5,423,731	$5,406,894
4	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				$4,386,629	$8,622,286	$8,501,393
5	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					$2,415,196	$4,952,061
6	Actual Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base						$1,930,669
7	Subtotal	$1,081,472	$3,627,024	$8,726,167	$16,155,514	$22,398,082	$26,685,011
8	Property Tax Recovery Adjustment	$263,025	$1,502,447	$1,089,549	$1,856,392	$2,207,523	$2,588,410
9	**Total Capital Investment Component of Revenue Requirement**	**$1,344,497**	**$5,129,471**	**$9,815,716**	**$18,011,906**	**$24,605,605**	**$29,273,421**

Line No.		As Filed Docket No. 5209, Page 33 Fiscal Year 2018 (a)	As Filed Docket No. 5209, Page 33 Fiscal Year 2019 (b)	As Filed Docket No. 5209, Page 33 Fiscal Year 2020 (c)	As Filed Docket No. 5209, Page 33 Fiscal Year 2021 (d)	As Filed Docket No. 5209, Page 33 Fiscal Year 2022 (e)	As Calculated Before DG Adjustment Fiscal Year 2023 (e)
	Capital Investment:						
10	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	1,059,288	2,060,611	1,984,661	1,931,906	1,879,763	1,805,484
11	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		1,521,500	4,332,013	4,165,495	4,012,227	4,042,712
12	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			2,368,560	5,638,935	5,436,943	5,419,949
13	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				4,393,352	8,635,547	8,514,586
14	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					2,395,558	4,912,322
15	Actual Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base						1,917,280
16	Subtotal	$1,059,288	$3,582,110	$8,685,233	$16,129,689	$22,360,037	$26,612,335
17	Property Tax Recovery Adjustment	263,025	1,493,525	1,079,265	1,850,478	2,191,610	2,578,312
18	**Total Capital Investment Component of Revenue Requirement**	**$1,322,314**	**$5,075,635**	**$9,764,498**	**$17,980,167**	**$24,551,648**	**$29,190,647**

Line No.		Variance Fiscal Year 2018 (a)	Variance Fiscal Year 2019 (b)	Variance Fiscal Year 2020 (c)	Variance Fiscal Year 2021 (d)	Variance Fiscal Year 2022 (e)	Variance Fiscal Year 2023 (e)	Total Adjustment (f)
	Capital Investment:							
19	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	22,184	43,159	41,560	40,434	39,325	40,255	226,916
20	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		1,755	5,878	5,714	5,555	5,543	24,445
21	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			(6,504)	(13,599)	(13,212)	(13,055)	(46,371)
22	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				(6,724)	(13,261)	(13,193)	(33,178)
23	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					19,638	39,738	59,376
24	Actual Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base						13,388	13,388
25	Subtotal	$22,184	$44,914	$40,934	$25,825	$38,045	$72,676	244,577
26	Property Tax Recovery Adjustment	-	8,922	10,284	5,913	15,913	10,098	51,130
27	**Total Capital Investment Component of Revenue Requirement - DG Adjustment**	**$22,184**	**$53,836**	**$51,218**	**$31,739**	**$53,957**	**$82,773**	**$295,707**

Column/Line Notes:
1 Page 2 of 36, Line 40 column a through g
2 Page 5 of 36, Line 42 column a through f
3 Page 10 of 36, Line 39 column a through e
4 Page 13 of 36, Line 40 column a through d
5 Page 17 of 36, Line 39 column a through c
6 Page 20 of 36, Line 39 column a through b
7 Lines 1 through 6
8 Page 32 of 36, Line 52 & 70
9 Line 7 + Line 8
10 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 1
11 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 2
12 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 3
13 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 4
14 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 5

Column/Line Notes:
15 Page 20, Line 4, Column a & b
16 Lines 10 through 15
17 Docket No. 5209 Reconciliation, Attachment SAB/JDO-1 (C), Page 33, Line 7
18 Line 16 + Line 17
19 Line 1 - Line 10
20 Line 2 - Line 11
21 Line 3 - Line 12
22 Line 4 - Line 13
23 Line 5 - Line 14
24 Line 6 - Line 15
25 Lines 19 through 24
26 Line 8 - Line 17
27 Line 25 + Line 26

PRE-FILED DIRECT TESTIMONY

OF

NATALIE HAWK

August 1, 2024

Table of Contents

I. <u>Introduction</u>

Q. Please state your full name and business address.

A. My name is Natalie Hawk, and my business address is 645 Hamilton Street, Allentown, Pennsylvania 18101.

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

A. I am employed by PPL Services Corporation ("Services Corporation") as the Director of tax accounting and reporting. My current responsibilities are primarily to oversee the accounting and reporting of 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 for all members of the PPL Corporation ("PPL") group of companies.

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 testified before the Rhode Island Public Utilities Commission (PUC) or other regulatory bodies?

A. Yes, I have testified before the PUC in support of the Company's filings in several proceedings of which two of the most recent filings are the Fiscal Year ("FY") 2025 Electric Infrastructure, Safety and Reliability ("ISR") Plan Filing, Docket No. 23-48-EL and the FY 2023 Electric ISR Plan Reconciliation Filing in Docket No. 5209.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the income tax components of the FY 2024 ISR revenue requirement. In addition, I will describe the FY 2024 tax updates used to calculate accumulated deferred income taxes ("ADIT") in rate base for the revenue requirement in this FY 2024 Electric ISR reconciliation filing. My testimony will also discuss tax updates to FY 2023, which resulted in a "true-up" to the revenue requirement adjustment as reflected on Attachment JDO-1 to the pre-filed direct testimony of Company witness Jeffrey D. Oliveira on Page 1 of 36, Line 14. Finally, my testimony will discuss the impacts of the above noted updates to the FY 2023 and FY 2024 hold harmless revenue credit calculations, as reflected on Attachment JDO-1, Page 1 of 36, Lines 17 and 18, and also shown on Attachments NH-1 and NH-2, respectively.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring Attachments NH-1 and NH-2 for the FY 2024 and FY 2023 hold harmless adjustments, respectively, which are discussed later in my testimony.

II. <u>Tax Updates</u>

Q. Does the updated FY 2024 revenue requirement in this filing include updates to the capital repairs deduction rate and the tax loss on retirements?

A. Yes, the Company used revised estimates for the capital repairs deduction rate of 44.63% and the tax loss on retirements of $17,900,612 to calculate ADIT for the FY 2024 rate base and revenue requirement. These revised estimates were based on three-quarters of the Company's 2023 calendar year tax return results, representing the April through December 2023 period. Although, the Company does not expect to file its final 2023 tax return until October of 2024, it does not anticipate further changes to the required tax information in the ISR relating to the capital repairs deduction rate and tax losses on retirements. In order to finalize FY 2024 tax activity for the ISR, the Company will sum three-quarters of its 2023 tax return activity, as will be reflected in this filing, and one-quarter of its 2024 tax return activity, representing the January through March 2024 period, to be updated in a subsequent ISR filing. The Company's 2024 tax return will not be filed with the Internal Revenue Service ("IRS") until October of 2025. The Company expects to finalize and reflect one-quarter of its 2024 tax return results in the tax updates to FY 2024 in the FY 2025 ISR Reconciliation, which will necessitate a tax true-up.

Q. Are there any tax updates to the FY 2023 revenue requirement reflected in the FY 2024 Electric ISR Reconciliation?

A. Yes, the Company has revised its vintage FY 2023 revenue requirement to reflect the following updates in Attachment JDO-1: (1) actual capital repairs deduction rate of 20.26%, as shown on Page 21, Line 2; (2) actual tax loss on retirements of $12,372,497, as shown on Page 21, Line 24, Columns (a) and (b); and (3) actual NOL utilization by

National Grid of $35,805,866, as shown on Page 26, Line 11. In order to finalize tax results for the FY 2023 period, the Company was required to refer to three separate tax returns. The first tax return is the short period tax return that was filed by National Grid for the period of April 1 through May 25, 2022, which is the date of which PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of Company from National Grid USA (the “Acquisition”). The second tax return is the short period tax return that was filed by PPL Corporation (“PPL”) for the period May 26 through December 31, 2022, which is PPL’s calendar year-end. The third tax return, which will be filed by PPL for the 2023 calendar year period is referenced in the analysis in order to derive the activity for the first quarter of 2023 and thereby correspond the information to the FY 2023 ISR year. PPL’s 2023 tax return will not be filed with the IRS until October 2024, but as previously stated, PPL does not anticipate any further changes to the tax information required for or relevant to the FY 2023 period. The impact of these changes created a net decrease in the revenue requirement of $40,831, which is made up of a FY 2023 income tax true-up downward adjustment of $909,143 and a FY 2023 hold harmless true-up upward adjustment of $868,312, found on Attachment JDO-1, Page 1 of 36, Lines 14 and 18, respectively. Additionally, these tax updates combined with plant in service and DG related updates created a downward adjustment to the FY 2023 period as reflected on Attachment JDO-1, Page 1 of 36, Line 10 to the pre-filed testimony of Mr. Oliveira.

Q. Are there any updates to the calculation of the excess deferred income tax amounts as a result of Tax Cuts and Jobs Act of 2017 ("2017 Tax Act")?

A. There are no new updates to the calculation of the excess deferred income tax amounts for FY 2024. Among the vintage years, only FY 2018 incremental ISR investment created excess deferred tax. As in prior fiscal years, the Company derived the excess deferred income tax amounts by multiplying the cumulative balance of ISR book to tax depreciation differences as of March 31, 2018 by the 10.55 percent change in the tax rate (31.55 percent average rate for FY 2018 minus 21 percent). As noted in the pre-filed testimony of Mr. Oliveira, this amount is reflected in the updated FY 2024 revenue requirement as shown on Line 27, Page 2 of Attachment JDO-1.

Q. Does the updated FY 2024 revenue requirement include bonus depreciation as a result of the 2017 Tax Act?

A. Yes. As indicated in the Company's FY 2024 Electric ISR Plan Section 5, 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. However, based on current industry practice, the Company has included actual FY 2019 and FY 2020 bonus depreciation in its calculation of accumulated deferred income taxes in the respective vintage year's rate base. The Company's FY 2024 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2024 investments.

III. Hold Harmless Adjustment

Q. Please describe the background of the hold harmless adjustment, as reflected in the attachments to your testimony.

A. The Acquisition was treated as an asset acquisition for tax purposes under Internal Revenue Code (IRC) §338(h)(10) ("the §338 election"), which, for the Company, resulted in the "step up" in the tax basis of the acquired assets to fair market value (effectively book value) and the corresponding elimination of most deferred tax liabilities. In addition, the NOL-related deferred tax assets were eliminated in FY 2023, as these NOLs were utilized by National Grid to offset the gain on the deemed asset sale for tax purposes. The reversal of nearly all deferred tax assets and liabilities, including NOL deferred tax assets, reduced net deferred tax liabilities, which increased rate base for each year represented in the ISR filings starting with the FY 2023 Electric ISR Plan (the year of the Acquisition) and forward.[1] Consequently, the increase in rate base necessarily increases the revenue requirement associated with the ISR mechanism.

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] Because of the §338 election, PPL generated tax-deductible goodwill, which creates cash tax benefits to the Company. The Company plans to share these cash tax benefits with customers 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 in the Acquisition. As discussed in Mr. Oliveira's pre-filed testimony, the Company is proposing to increase the FY 2024 revenue requirement by the calculated hold harmless amounts totaling $30,228 as shown on Attachment JDO-1, Page 1, Lines 17 and 18 or in Attachments NH-1, Page 1, Line 23(a) and NH-2, Page 1, Line 23(e).

[1] As the Company has not filed for or been involved in a rate case proceeding since 2018, the increase in rate base and corresponding hold harmless commitment has not been relevant apart from ISR proceedings since the date of acquisition.

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

Q. Please describe any impacts of the Acquisition on the presentation of the revenue requirement calculations.

A. As stated above, the Acquisition resulted in the reversal of book and tax timing differences and the elimination of the related deferred taxes. In addition, tax depreciation starts over on a new tax basis equal to net book value on the date of the Acquisition. The Company has reflected these impacts of the Acquisition in the presentation of its revenue requirement calculations in Schedule JDO-1, as described in Mr. Oliveira's testimony. Starting in FY 2023, each ISR plan year, FY 2018 through FY 2023, will include a new tax basis for the Company. Further, an ADIT liability balance will increase as accelerated tax depreciation is taken each year on increased tax basis of the acquired assets.

Q. Please describe the purpose of the attachments to your testimony.

A. Attachments NH-1 and NH-2 show the calculation of the hold harmless credits to the FY 2024 revenue requirement. To determine the impact of the Acquisition to customers and the required hold harmless adjustment, the Company must compare actual ADIT in rate base to hypothetical ADIT in rate base as if the Acquisition did not occur and apply the weighted average cost of capital to the difference to determine the revenue requirement impact on all pre-acquisition periods presented in the ISR.

Attachment NH-1 reflects the hold harmless revenue requirement impact of FY 2024 and Attachment NH-2 reflects the hold harmless revenue requirement true-up adjustment for FY 2023. Page 1 of both Attachments NH-1 and NH-2 provide the cost of capital factors, the change in ADIT on the “with and without acquisition” scenarios from Page 2 and the revenue requirement impacts of the Acquisition to determine the hold harmless revenue adjustment needed to make customers whole.

Q. Please describe any updates to the hold harmless adjustment presented in this filing?

A. For FY 2023, the hold harmless true-up adjustment reflects an increase to the revenue requirement of $868,312 on Attachment NH-2, Page 1, Line 23, Column (e) and is primarily related to the increase in the net operating loss (“NOL”) utilization in the “with acquisition” scenario as compared to the “without acquisition” scenario. In the “with acquisition” scenario, the estimated NOL related deferred tax assets reversals increased from $937,665, as reflected in the FY 2023 Electric ISR Reconciliation Filing, to $23,627,830 in this FY 2024 Electric ISR Reconciliation filing. The Acquisition allowed National Grid to utilize all of the Company’s NOLs whereas in the “without Acquisition” scenario, the NOL is hypothetically utilized over a 7-year period, which was approved in the FY 2025 Electric ISR Plan in Docket No. 23-48-EL. The “without acquisition” scenario reflected a lower increase in NOL related deferred tax asset reversals (from $937,665 to $3,375,404) than the “with acquisition scenario” due to the longer utilization period. An increase in NOL utilization reduces deferred tax assets, which decreases rate base and the resulting revenue requirement. Since the Acquisition decreases the revenue requirement, as it relates to NOL utilization, the hold harmless adjustment also decreases.

For FY 2024, the hold harmless adjustment reduced the revenue requirement by $838,084, as reflected on Attachment NH-1, Page 1, Line 23. This hold harmless adjustment decreased by $741,449 from the $1,579,533 estimate calculated for the FY 2024 Electric ISR Plan filing primarily due to the increase in NOL utilization in FY 2023 discussed above. The FY 2023 NOL tax update impacts FY 2024 because the NOL related deferred tax impacts reduce rate base, on which the revenue requirement is determined by averaging the rate base amounts calculated at the end of the prior and the current periods. Other factors that contributed to the change in the hold harmless adjustment are (1) plant updates related to DG projects prior to the Acquisition date and their related tax impacts; (2) FY 2022 and FY 2023 tax updates to adjust the repairs reduction rate, the tax loss on retirements and NOLs to the final tax returns, which were not available at the time of the Electric ISR FY 2024 Plan filing; (3) FY 2024 estimated tax updates to adjust the repairs reduction rate and tax loss on retirements based on the PPL's 2023 tax return to be filed in October 2024; and (4) the change to a 7-year NOL utilization period discussed above.

IV. Conclusion

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment NH-1

Hold Harmless Calculation
FY 2024 Electric Infrastructure, Safety and Reliability Reconciliation

FY 2024 Impact of Elimination of ADIT and Hold Harmless Commitment
Plan Year 2024 - April 2023-March 2024

Inputs

			Column (A)
1	Tax Rate		21.00%
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 / (Lines 2 + 3) * Line 7 + Line 3 / (Lines 2 + 3) * Line 8	4.585%
10	Cost of Equity		9.275%
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.2300%**
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**6.975%**
13	Rate Base - PPL (after purchase)		$ 215,678,916
14	Rate Base - NG (before sale)		$ 205,495,623
15	**Deferred Taxes / Hold Harmless**	**Lines 13 - 14**	**$ 10,183,293**	Elimination of Deferred Taxes

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 shown on Line 30 is the revenue credit reflected on Line 23.

			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 Acquistion did not occur**	**Difference**	
			(a)	(b)	(c) = (a) - (b)	
16	Rate Base after Acqusition	Line 13	215,678,916	215,678,916	-	
17	ADIT Adjustment	- Line 15	-	(10,183,293)	10,183,293	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**215,678,916**	**205,495,623**	**10,183,293**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,850,436	4,621,422	229,014	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	10,192,150	9,710,927	481,223	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,709,306	2,581,386	127,920	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**17,751,891**	**16,913,734**	**838,157**	
23	Revenue Adjustment	- Line 15 * Line 11	(838,084)	-	(838,084)	Note 1
24	**Total Revenue**	**Lines 22 + 23**	**16,913,807**	**16,913,734**	**73**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,621,422	4,621,422	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,581,401	2,581,386	15	
27	**Net Income**	**Lines 24 - 25 - 26**	**9,710,984**	**9,710,927**	**57**	
	Impact of Transaction					
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	3,152,792			
29	Cash Tax Benefit at 21%	Line 28 * Line 1	662,086			
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	838,084			

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.

Average ISR Rate Base after Deferred Tax Proration

		Post-Acquisition	Prorated	Post-Acquisition After Proration		No Acquisition	Prorated	No Acquisition After Proration	
		(a)	(b)	(c)		(d)	(e)	(f)	
1	**Plan Year 2024**								
2	FY 2018	12,978,736	100%	12,978,736		13,538,805	100%	13,538,805	
3	FY 2019	25,408,484	100%	25,408,484		22,303,935	100%	22,303,935	
4	FY 2019 Intangible	1,230,535	100%	1,230,535		683,474	100%	683,474	
5	FY 2020	41,161,907	100%	41,161,907		36,887,190	100%	36,887,190	
6	FY 2021	65,898,687	100%	65,898,687		61,825,876	100%	61,825,876	
7	FY 2022	40,420,521	100%	40,420,521		35,430,551	100%	35,430,551	
8	FY 2023	28,580,046	100%	28,580,046		34,825,792	100%	34,825,792	
9	Total	215,678,916		215,678,916	Page 1, Line 13	205,495,623		205,495,623	Page 1, Line 14

Attachment NH-2

True-Up Calculation for FY 2023
FY 2024 Electric Infrastructure, Safety and Reliability Reconciliation Hold Harmless

FY 2023 Impact of Elimination of ADIT and Hold Harmless Commitment
Plan Year 2023 - April 2022-March 2023 Revised

Inputs

			Column (A)	
1	Tax Rate		21.00%	
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 / (Lines 2 + 3) * Line 7 + Line 3 / (Lines 2 + 3) * Line 8	4.585%	
10	Cost of Equity		9.275%	
11	Revenue WACC (pre-tax)	Line 9 * Line 5 + (Line 10/(1-Line 1))*Line 6	**8.2300%**	
12	WACC (after-tax)	(Line 9 * Line 5) + (Line 10 * Line 6)	**6.975%**	
13	Rate Base - PPL (after purchase)		$ 198,878,472	
14	Rate Base - NG (before sale)		$ 200,202,923	
15	**Deferred Taxes / Hold Harmless**	**Lines 13 - 14**	**$ (1,324,451)**	Elimination of Deferred Taxes

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 shown on Line 30 is the revenue credit reflected on Line 23.

			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		Difference per FY2023 Electric Reconciliation Filed in Docket 5209, Attachment NH-1	FY2023 Adjustment for FY2024 Reconciliation
			(a)	(b)	(c) = (a) - (b)		(d)	(e) = (c) - (d)
16	Rate Base after Acqusition	Line 13	198,878,472	198,878,472	-		-	-
17	ADIT Adjustment	- Line 15	-	1,324,451	(1,324,451)		9,226,124	(10,550,575)
18	**Adjusted Rate Base**	**Lines 16 + 17**	**198,878,472**	**200,202,923**	**(1,324,451)**		**9,226,124**	**(10,550,575)**
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,472,608	4,502,394	(29,786)		207,488	(237,274)
20	Equity Return (9.275%)	Lines 18 * 6 * 10	9,398,226	9,460,814	(62,588)		435,991	(498,579)
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,498,263	2,514,900	(16,637)		115,896	(132,533)
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**16,369,096**	**16,478,108**	**(109,012)**		**759,375**	**(868,387)**
23	Revenue Adjustment	- Line 15 * Line 11	109,002	-	109,002	Note 1	(759,310)	868,312
24	**Total Revenue**	**Lines 22 + 23**	**16,478,099**	**16,478,108**	**(9)**		**65**	**(74)**
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,502,394	4,502,394	-			-
26	Tax Expense	(Lines 24 - 25) * Line 1	2,514,898	2,514,900	(2)		14	(16)
27	**Net Income**	**Lines 24 - 25 - 26**	**9,460,807**	**9,460,814**	**(7)**		**51**	**(58)**
	Impact of Transaction							
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	(410,056)					
29	Cash Tax Benefit at 21%	Line 28 * Line 1	(86,112)					
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	(109,002)					

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.

Average ISR Rate Base after Deferred Tax Proration

		Post-Acquisition	Prorated	Post-Acquisition After Proration		No Acquisition	Prorated	No Acquisition After Proration	
		(a)	(b)	(c)		(d)	(e)	(f)	
1	**Plan Year 2023**								
2	FY 2018	13,921,065	100%	13,921,065		14,172,285	100%	14,172,285	
3	FY 2019	25,232,023	100%	25,232,023		23,649,292	100%	23,649,292	
4	FY 2019 Intangible	1,649,877	100%	1,649,877		1,076,584	100%	1,076,584	
5	FY 2020	41,394,719	100%	41,394,719		39,213,020	100%	39,213,020	
6	FY 2021	67,497,071	100%	67,497,071		65,347,535	100%	65,347,535	
7	FY 2022	40,213,686	100%	40,213,686		37,622,114	100%	37,622,114	
8	FY 2023	8,970,031	100%	8,970,031		19,122,093	100%	19,122,093	
9	Total	198,878,472		198,878,472	Page 1, Line 13	200,202,923		200,202,923	Page 1, Line 14

PRE-FILED DIRECT TESTIMONY

OF

TYLER G. SHIELDS

August 1, 2024

Table of Contents

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Tyler G. Shields, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Please state your position.

A. I am employed by the PPL Services Corporation ("Services Corporation") as a Rates and Regulatory Specialist. My current duties primarily pertain to revenue requirement and pricing support for the Narragansett Electric Company d/b/a Rhode Island Energy (the "Company").

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics from the University of Connecticut in 2013.

Q. Please describe your professional background.

A. In March 2015, I began my career as a pricing analyst at Granite Telecommunications in Quincy, Massachusetts. In February 2017, I was promoted to product pricing team lead. My responsibilities included auditing customer accounts and maintaining the pricing and billing databases to ensure accuracy. In January 2021, I was hired by Charles Stark Draper Laboratory as a Program Analyst where my duties included the creation of pricing proposals for prospective clients and the validation of financial data for key stakeholders on a weekly basis. In November 2022, I joined the Services Corporation in my current role.

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

A. Yes. I provided pre-filed testimony/and or testified at hearings before the PUC regarding the Company's Fiscal Year ("FY") 2023 Electric Revenue Decoupling Mechanism ("RDM") Reconciliation filing in Docket No. 23-16-EL, the Company's Gas RDM Reconciliation filing in Docket No. 23-23-NG, the Company's Distribution Adjustment Charge ("DAC") and Gas Cost Recovery ("GCR") filings in Docket No. 23-23-NG, the Company's FY 2023 Electric Infrastructure, Safety, and Reliability ("ISR") Plan Annual Reconciliation Filing in Docket No. 5209, the Company's proposed FY 2025 Gas ISR Plan in Docket No. 23-49-NG, the Company's proposed FY 2025 Electric ISR Plan in Docket No. 23-48-EL, the Company's 2024 Annual Retail Rate Filing in Docket No. 24-07-EL, the Company's Fiscal Year 2024 Electric RDM Reconciliation filing in Docket No. 24-18-EL, and the Company's Gas RDM Reconciliation filing in Docket No. 24-29-NG.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the Company's Infrastructure, Safety, and Reliability Provision, R.I.P.U.C. No. 2255 effective September 1, 2022 ("ISR Provision"), resulting from the reconciliation of actual costs and revenue associated with the Fiscal Year ("FY") 2024 ISR Plan ("ISR Plan" or "Plan"). In support of the proposed factors, my testimony presents the following:

- the results of the annual reconciliation of the actual FY 2024 capital investment ("CapEx") revenue requirement and the Operation and Maintenance ("O&M") expense to the actual revenue billed;
- the final status of the credit of the FY 2022 CapEx and O&M reconciliations;
- the status of the credit of the FY 2023 CapEx and O&M reconciliations;
- the calculation of the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2024; and
- the typical bill impacts related to the proposed reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of FY 2024 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2024 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the final status of the return to customers of the FY 2022 CapEx net over-recovery reconciliation balance as well as the status of the return to customers of the FY 2023 CapEx net over-recovery reconciliation balance;
- Section V presents the results of the FY 2024 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the final status of the return to customers of the FY 2022 O&M over-recovery reconciliation balance as well as the status of the recovery from customers of the FY 2023 O&M under-recovery reconciliation balance; and
- Section VI presents the rate class bill impact analysis.

III. Summary of FY 2024 Capex and O&M Reconciliations

Q. Please summarize the results of the FY 2024 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2024 CapEx and O&M reconciliations is presented in Attachment TGS-1. Pursuant to the ISR Provision, the annual reconciliations compare the actual revenue billed during the Plan year through the approved CapEx and O&M Factors to the CapEx and O&M revenue requirement based on actual costs incurred. The calculation of the revenue requirement is presented in the testimony of Company Witness Jeffrey D. Oliveira. As reflected in Attachment TGS-1, the result of the CapEx reconciliation is a net under-recovery of approximately $0.5 million; the result of the O&M reconciliation is a net under-recovery of approximately $0.8 million.

Q. Please briefly summarize the operation of the tariff provision that enables the Company to recover certain costs through the ISR Plan.

A. In accordance with the ISR Provision, the Company is allowed to recover the revenue requirement related to capital investments through CapEx Factors and to recover certain expenditures for Inspection and Maintenance ("I&M") and Vegetation Management ("VM") activities through O&M Factors. In the ISR Plan filing for the upcoming year, the Company determines the CapEx Factors, which are designed to recover the revenue requirement on the forecasted capital investment for the ISR Plan's investment year plus cumulative capital investment in prior years' ISR Plans, as well as the O&M Factors based on the forecasted O&M expense for the Plan year. On an annual basis, the Company is required to reconcile the annual CapEx revenue requirement on actual cumulative ISR capital investment and the actual O&M expense incurred to actual billed revenue generated from the CapEx Factors and the O&M Factors, respectively. The over or under-recovered balances resulting from the CapEx and O&M reconciliations are either credited to or recovered from customers through the CapEx Reconciling Factors and the O&M Reconciling Factor, respectively.

IV. Capex Reconciliation and Proposed Capex Reconciling Factors

Q. What is the result of the CapEx reconciliation for FY 2024?

A. The FY 2024 CapEx reconciliation by rate class is presented in Attachment TGS-2, page 1. Line (5) represents the CapEx revenue billed during the period April 1, 2023 through March 31, 2024 of approximately $38.8 million. Line (4) reflects the CapEx revenue requirement on actual cumulative ISR capital investment of approximately $39.4 million. Line (6) identifies the net under-recovery by rate class of the CapEx revenue requirement, which totals approximately $0.5 million.

Q. Why has the Company prepared the CapEx reconciliation by rate class?

A. The ISR Provision requires that the CapEx Reconciling Factors be calculated as class-specific per-kWh factors designed to recover or credit the under- or over-recovery of the actual Cumulative Revenue Requirement, as allocated to each rate class by the Rate Base Allocator, for the prior fiscal year. The Rate Base Allocator is the percentage of total rate base allocated to each rate class determined in the most recently approved allocated cost of service study. Page 1, Line (4) of Attachment TGS-2 shows the allocation of the CapEx revenue requirement to each rate class based upon the Rate Base Allocator approved in the Company's 2017 general rate case in Docket No. 4770.

Q. Please describe the results of the rate class reconciliation.

A. As shown in Attachment TGS-2, page 1, the allocated FY 2024 revenue requirement on actual cumulative capital investment (Line (4)) is subtracted from the CapEx Factor revenue billed for each rate class (Line (5)), resulting in the net under-recovery of approximately $0.5 million (Line (6)). The detail of the CapEx revenue billed for each rate class is provided in Attachment TGS-2, page 2.

Q. Please describe the amounts included on Line (7) of Attachment TGS-2, Page 1.

A. The amounts presented on Page 1 Line (7) reflect the final balance of the net over-recovery resulting from the FY 2022 CapEx reconciliation. The net recovery of the FY 2022 CapEx reconciliation balance is presented on page 3. Of the $4.7 million net over-recovery for FY 2022 to be returned to customers via CapEx Reconciling Factors approved by the PUC, the Company returned to customers $4.5 million from October 1, 2022 through September 30, 2023. The remaining balance is a net over-recovery amount of approximately $0.2 million, as shown on Attachment TGS-2, Page 1, Line (7), Column (a). As described in Docket No. 4682, the Company is including each rate class' residual balance associated with the FY 2022 reconciliation as an adjustment to the FY 2024 CapEx reconciliation balance.

Q. How is the Company proposing to recover the FY 2024 CapEx net under-recovery?

A. The Company is proposing to implement a CapEx Reconciling Factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment TGS-2, page 1. The over or under-recovery by rate class on Line (8) is divided by each rate class' forecasted kWh deliveries for the period October 1, 2024 through September 30, 2025 on Line (9). The class-specific CapEx Reconciling Factors are shown on Line (10).

Q. Is the Company providing the status of the net over-recovery from the FY 2023 CapEx reconciliation?

A. Yes. The status of the FY 2023 CapEx reconciliation net over-recovery balance is presented in Attachment TGS-2, page 4. As of June 30, 2024, the balance reflects a remaining net over-recovery of approximately $3.1 million, which the Company will continue to return to customers through September 30, 2024.

V. O&M Reconciliation and Proposed O&M Reconciling Factor

Q. What is the result of the O&M reconciliation for FY 2024?

A. The O&M reconciliation for FY 2024 is presented in Attachment TGS-3, page 1. Line (1) shows the actual O&M expense for FY 2024 of approximately $14.9 million, which is supported in the testimony of Company Witness Jeffrey D. Oliveira. Line (2) shows O&M revenue billed through the O&M Factors from April 1, 2023 through

March 31, 2024 of approximately $14.1 million. Line (3) shows the difference of approximately $0.8 million, representing an under-recovery of actual O&M expense.

Q. Please describe the amount included on Line (4).

A. The amount presented on Line (4) reflects the remaining balance resulting from the FY 2022 O&M reconciliation of $0. The over-recovered balance for FY 2022 of $69,828 was too small to generate a billable factor and so the Company carried this over-recovery amount forward and included it as an adjustment to the FY 2023 O&M reconciliation balance. Consequently, a final reconciliation of the FY 2022 O&M reconciliation over-recovery in this filing is not necessary since it was already included as an adjustment to the FY 2023 O&M reconciliation balance. [1]

Q. Is the Company providing the O&M Factor revenue?

A. Yes. Attachment TGS-3, page 2 presents the O&M Factor revenue billed by month.

[1] Refer to the Company's FY 2023 Electric ISR Plan Annual Reconciliation Filing (Docket No. 5209), the Direct Testimony of Tyler G. Shields, Page 11, Line 17, to Page 12, Line 5: "Pursuant to the ISR Provision, the amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation. Therefore, the Company would typically present the final reconciliation of the balance from the FY 2022 O&M reconciliation in the FY 2024 ISR Reconciliation Filing and include the residual balance of the FY 2022 O&M reconciliation with the results of the FY 2024 O&M reconciliation and would propose an O&M Reconciling Factor on the total. In this instance, however, the Company is proposing to include the carry forward FY 2022 over-recovery balance as an adjustment to the FY 2023 O&M reconciliation balance. Consequently, this treatment of the FY 2022 over-recovery balance effectively serves as a final reconciliation of this balance."

Q. What is the proposed O&M Reconciling Factor?

A. The proposed O&M Reconciling Factor is calculated on Attachment TGS-3, page 1. The total amount to be recovered from customers of $808,366 on Line (5) is divided by the forecasted kWh during the period October 1, 2024 through September 30, 2025, on Line (6), resulting in a charge of 0.010¢ per kWh on Line (7). Pursuant to the ISR Provision, the O&M Reconciling Factor is a uniform per-kWh factor.

Q. Is the Company providing the status of the FY 2023 O&M reconciliation under-recovery?

A. Yes. The status of the balance from the FY 2023 O&M reconciliation is presented in Attachment TGS-3, page 4. As of June 30, 2024, there is a remaining under-recovery balance of approximately $0.8 million, which the Company will continue to recover from customers through September 30, 2024.

Q. How does the Company propose to credit or recover the residual balance at September 30, 2024?

A. Pursuant to the ISR Provision, the amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation. Therefore, the Company will present the final reconciliation of the balance from the FY 2023 O&M reconciliation in the FY 2025 ISR Reconciliation Filing and include the residual balance of the FY 2023 O&M reconciliation with the results of the FY 2025 O&M reconciliation and will propose an O&M Reconciling Factor on the total.

VI. Typical Bill Analysis

Q. Is the Company providing a typical bill analysis to illustrate the impact of the proposed rates on each of the Company's rate classes?

A. Yes. The typical bill analysis illustrating the monthly bill impact of the proposed rate changes for each rate class is provided in Attachment TGS-4. The impact of the proposed CapEx Reconciling Factor of $0.00020 per kWh and the proposed O&M Reconciling Factor of $0.00010 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is an increase of $0.86, or approximately 0.6%, from $137.54 to $138.40.

VII. Summary of Retail Delivery Rates

Q. Is the Company providing a proposed Summary of Retail Delivery Rates, R.I.P.U.C. No. 2095, reflecting the reconciling factors proposed in this filing?

A. No, not at this time. The Company will also be submitting its Pension and Post-retirement Benefits Other than Pension Adjustment Factor ("PAF") filing in August 2024 in which the Company will propose a PAF, effective October 1, 2024. The Company will file a

Summary of Retail Delivery Rates tariff reflecting all rates proposed for October 1, 2024 in compliance with the PUC's orders in this proceeding and the PAF proceedings.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment TGS-1

FY 2024 ISR Plan Annual Reconciliation Summary

FY 2024 ISR Plan Annual Reconciliation Summary

		CapEx (a)	O&M (b)	Total (c)
(1)	Actual Revenue Requirement	$ 39,352,303	$14,929,779	$54,282,082
(2)	Revenue Billed	$38,822,110	$14,121,413	$52,943,523
(3)	Total Over/(Under) Recovery	($530,193)	($808,366)	($1,338,559)

(1)	Column (a): Attachment JDO-1, Page 1 of 36:		
	Line (15), Column (b): Total Capital Investment Component of Revenue Requirement	$	39,026,367
	Line (17) + (18), Column (b): Per Tax Hold Harmless Adjustment	$	30,228
	Line (20), Column (b): Adjustment for DG Project Review	$	295,707
	Total Net Capital Investment Component of Revenue Requirement	$	39,352,303
	Column (b): Attachment JDO-1, Page 1 of 36, Line (4), Column (b)		
(2)	Column (a): Attachment TGS-2, page 1, Line (5)		
	Column (b): Attachment TGS-3, page 1, line (2)		
(3)	Line (2) - Line (1)		
(c)	Sum of Columns (a) and (b)		

Attachment TGS-2

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2024 ISR Plan
For the Recovery/(Refund) Period October 1, 2024 through September 30, 2025

		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	Lighting S-05/S-06 S-10/S-14 (f)	Propulsion X-01 (g)
(1)	Actual FY2024 Capital Investment Revenue Requirement	$39,352,303						
(2)	Total Rate Base ($000s)	$729,512	$404,995	$75,009	$117,155	$123,849	$8,296	$208
(3)	Rate Base as Percentage of Total	100.00%	55.52%	10.28%	16.06%	16.98%	1.14%	0.03%
(4)	Allocated Actual FY2024 Capital Investment Revenue Requirement	$39,352,303	$21,846,777	$4,046,235	$6,319,730	$6,680,827	$447,514	$11,220
(5)	CapEx Revenue Billed	$38,822,110	$21,039,238	$3,480,300	$6,599,942	$7,406,642	$280,049	$15,939
(6)	Total Over/(Under) Recovery for FY 2024	($530,193)	($807,539)	($565,935)	$280,212	$725,815	($167,465)	$4,719
(7)	Remaining Over/(Under) For FY 2022	$154,599	$161,178	($7,345)	$15,310	($2,010)	($12,092)	($442)
(8)	Total Over/(Under) Recovery	($375,594)	($646,361)	($573,280)	$295,522	$723,805	($179,557)	$4,277
(9)	Forecasted kWhs - October 1, 2024 through September 30, 2025	7,349,669,060	3,191,926,845	702,752,577	1,197,421,358	2,204,275,097	36,020,966	17,272,218
(10)	Proposed Class-specific CapEx Reconciling Factor Charge/(Credit) per kWh		$0.00020	$0.00081	($0.00024)	($0.00032)	$0.00498	($0.00024)

(1) Column (a): Attachment JDO-1, Page 1 of 36:

Line (15), Column (b): Total Capital Investment Component of Revenue Requirement	$	39,026,367
Line (17) + (18), Column (b): Per Tax Hold Harmless Adjustment	$	30,228
Line (20), Column (b): Adjustment for DG Project Review	$	295,707
Total Net Capital Investment Component of Revenue Requirement	$	39,352,303

(2) per R.I.P.U.C. Docket No. 4770/4780, Compliance Attachment 6, (Schedule 1A), Page 1, Line 9
(3) Line (2) ÷ Line (2), Column (a)
(4) Line (1) x Line (3)
(5) per Page 2
(6) Line (5) - Line (4)
(7) per Page 3
(8) Line (6) + Line (7)
(9) per Company forecast
(10) -1 x (Line (8) ÷ Line (9)), truncated to 5 decimal places

Fiscal Year 2024 CapEx Reconciliation
For the Period April 1, 2023 through March 31, 2024
For the Recovery/Refund Period October 1, 2024 through September 30, 2025

CapEx Revenue By Rate Class:

		Residential A-16 / A-60			Small C&I C-06			General C&I G-02			Demand B-32 / G-32		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-23	$ 569,998.00	$ (82,913)	$652,911	$ 64,512.00	$ (1,874)	$66,386	$ 192,622.00	$ (29,424)	$222,046	$ 58,169.00	$ (37,653)	$95,822
	May-23	$ 1,154,197.00	($165,623)	$1,319,820	$ 238,474.00	($3,708)	$242,182	$ 480,572.00	($68,068)	$548,640	$ 539,131.00	($84,030)	$623,161
	Jun-23	$ 1,248,455.00	($179,054)	$1,427,509	$ 254,279.00	($4,144)	$258,423	$ 471,640.00	($67,006)	$538,646	$ 519,665.00	($82,955)	$602,620
	Jul-23	$ 1,904,722.00	($273,099)	$2,177,821	$ 302,674.00	($4,546)	$307,220	$ 494,091.00	($78,769)	$572,860	$ 555,038.00	($88,851)	$643,889
	Aug-23	$ 2,139,479.00	($306,720)	$2,446,199	$ 333,490.00	($5,146)	$338,636	$ 504,964.00	($84,713)	$589,677	$ 593,129.00	($100,262)	$693,391
	Sep-23	$ 1,876,540.00	($269,031)	$2,145,571	$ 314,438.00	($4,637)	$319,075	$ 550,546.00	($87,549)	$638,095	$ 554,599.00	($92,067)	$646,666
	Oct-23	$ 1,342,037.00	($254,141)	$1,596,178	$ 268,824.00	($17,441)	$286,265	$ 462,700.00	($97,209)	$559,909	$ 543,600.00	($119,930)	$663,530
	Nov-23	$ 1,141,786.00	($301,993)	$1,443,779	$ 231,264.00	($32,933)	$264,197	$ 372,481.00	($119,504)	$491,985	$ 422,401.00	($148,612)	$571,013
	Dec-23	$ 1,286,096.00	($340,515)	$1,626,611	$ 240,465.00	($32,867)	$273,332	$ 340,691.00	($122,061)	$462,752	$ 421,920.00	($151,810)	$573,730
	Jan-24	$ 1,553,418.00	($411,304)	$1,964,722	$ 271,302.00	($36,606)	$307,908	$ 387,396.00	($136,427)	$523,823	$ 448,582.00	($155,605)	$604,187
	Feb-24	$ 1,354,384.00	($358,600)	$1,712,984	$ 260,763.00	($36,529)	$297,292	$ 407,361.00	($138,987)	$546,348	$ 417,914.00	($148,274)	$566,188
	Mar-24	$ 1,294,803.00	($342,923)	$1,637,726	$ 263,486.00	($37,443)	$300,929	$ 445,338.00	($147,268)	$592,606	$ 442,312.00	($159,697)	$602,009
(2)	Apr-24	$ 698,677.00	$ (188,730)	$887,407	$ 194,718.00	$ (23,737)	$218,455	$ 231,718.00	$ (80,837)	$312,555	$ 431,390.00	$ (89,046)	$520,436
	Total	$17,564,592	($3,474,646)	$21,039,238	$3,238,689	($241,611)	$3,480,300	$5,342,120	($1,257,822)	$6,599,942	$5,947,850	($1,458,792)	$7,406,642

		Lighting S-05/S-06/S-10/S-14			Propulsion X-01		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-23	$ (5,353.00)	$ 356	($5,709)	$ 444.00	$ (117)	$561
	May-23	$ (673.00)	($212)	($461)	$ 1,031.00	$277	$754
	Jun-23	$ 43,378.00	$1,589	$41,789	$ 1,027.00	($277)	$1,304
	Jul-23	$ 8,389.00	$221	$8,168	$ 1,046.00	($282)	$1,328
	Aug-23	$ 26,556.00	$888	$25,668	$ 1,133.00	($305)	$1,438
	Sep-23	$ 37,981.00	$1,274	$36,707	$ 1,093.00	($294)	$1,387
	Oct-23	$ 33,919.00	($417)	$34,336	$ 1,064.00	($455)	$1,519
	Nov-23	$ 32,330.00	($2,668)	$34,998	$ 785.00	($788)	$1,573
	Dec-23	$ 43,453.00	($3,648)	$47,101	$ 733.00	($779)	$1,512
	Jan-24	$ 38,596.00	($3,187)	$41,783	$ 616.00	($654)	$1,270
	Feb-24	$ 29,462.00	($2,433)	$31,895	$ 666.00	($708)	$1,374
	Mar-24	$ (17,310.00)	$1,476	($18,786)	$ 562.00	($597)	$1,159
(2)	Apr-24	$ 2,355.00	$ (205)	$2,560	$ 368.00	$ (392)	$760
	Total	$273,083	($6,966)	$280,049	$10,568	($5,371)	$15,939

(1) Reflects revenue associated with consumption on and after April 1
(2) Reflects revenue associated with consumption prior to April 1

(a) From monthly revenue reports
(b) per Page 3 and Page 4
(c) Column (a) - Column (b)

The Narragansett Electric Company
d/b/a Rhode Island Energy
RIPUC Docket No. 22-53-EL
FY 2024 Electric Infrastructure, Safety,
and Reliability Plan Reconciliation Filing
Attachment TGS-2
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Fiscal Year 2022 CapEx Reconciliation of Over Recovery
For the Period April 1, 2021 through March 31, 2022
For the Recovery/Refund Period October 1, 2022 through September 30, 2023

		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery	$4,708,093		$2,779,938		$42,790		$895,217		$1,011,808
(2)	CapEx Reconciling Factors			($0.00089)		($0.00007)		($0.00072)		($0.00045)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-22	($148,743)	85,204,022	($75,832)	23,107,529	($1,618)	49,398,923	($35,567)	80,351,734	($36,158)
	Nov-22	($332,338)	205,825,860	($183,185)	52,434,803	($3,670)	96,756,177	($69,664)	170,085,475	($76,538)
	Dec-22	($352,405)	222,707,568	($198,210)	51,238,186	($3,587)	92,848,832	($66,851)	187,064,579	($84,179)
	Jan-23	($405,015)	279,075,594	($248,377)	59,757,823	($4,183)	102,366,040	($73,704)	177,799,964	($80,010)
	Feb-23	($346,654)	233,200,351	($207,548)	56,902,348	($3,983)	95,904,722	($69,051)	149,557,169	($67,301)
	Mar-23	($356,407)	226,935,035	($201,972)	58,631,401	($4,104)	95,944,730	($69,080)	182,947,833	($82,327)
	Apr-23	($352,518)	216,593,423	($192,768)	62,227,398	($4,356)	95,012,227	($68,409)	194,534,902	($87,541)
	May-23	($321,364)	186,093,205	($165,623)	52,966,249	($3,708)	94,538,877	($68,068)	186,734,153	($84,030)
	Jun-23	($331,847)	201,183,955	($179,054)	59,195,688	($4,144)	93,063,487	($67,006)	184,344,967	($82,955)
	Jul-23	($445,326)	306,852,306	($273,099)	64,942,433	($4,546)	109,401,871	($78,769)	197,447,175	($88,851)
	Aug-23	($496,258)	344,628,663	($306,720)	73,508,219	($5,146)	117,657,523	($84,713)	222,803,962	($100,262)
	Sep-23	($452,304)	302,281,792	($269,031)	66,244,412	($4,637)	121,595,922	($87,549)	204,592,816	($92,067)
(4)	Oct-23	($212,315)	131,843,567	($117,341)	35,047,617	($2,453)	57,605,961	($41,476)	114,665,256	($51,599)
(5)	Total	($4,553,494)		($2,618,760)		($50,135)		($879,907)		($1,013,818)
(6)	Ending Over/(Under) Recovery	$154,599		$161,178		($7,345)		$15,310		($2,010)

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		($23,974)		$2,314
(2)	CapEx Reconciling Factors		$0.00040		($0.00014)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-22	1,344,699	$538	760,670	($106)
	Nov-22	2,452,601	$981	1,868,983	($262)
	Dec-22	1,810,938	$724	2,156,486	($302)
	Jan-23	3,765,334	$1,506	1,765,773	($247)
	Feb-23	3,743,421	$1,497	1,912,668	($268)
	Mar-23	3,314,688	$1,326	1,785,069	($250)
	Apr-23	2,070,163	$828	1,946,335	($272)
	May-23	(530,232)	($212)	(1,979,583)	$277
	Jun-23	3,972,139	$1,589	1,975,517	($277)
	Jul-23	553,643	$221	2,011,995	($282)
	Aug-23	2,220,895	$888	2,179,480	($305)
	Sep-23	3,185,673	$1,274	2,101,679	($294)
(4)	Oct-23	1,805,142	$722	1,202,665	($168)
(5)	Total		$11,882		($2,756)
(6)	Ending Over/(Under) Recovery		($12,092)		($442)

(1) Docket No. 5209, Attachment TGS-5, Page 1, Line (20)
(2) Docket No. 5098, Attachment PRB-2, Page 1, Line (10)
(3) Prorated for usage on and after October 1, 2022
(4) Prorated for usage prior to October 1, 2023
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

(a) Sum of Column (b) from each rate
(b) From Company revenue report
(c) Column (b) x Line (2) CapEx Reconciling Factor

The Narragansett Electric Company
d/b/a Rhode Island Energy
RIPUC Docket No. 22-53-EL
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Attachment TGS-2
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Fiscal Year 2023 CapEx Reconciliation of Over Recovery
For the Period April 1, 2022 through March 31, 2023
For the Recovery/Refund Period October 1, 2023 through September 30, 2024

		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery	$8,705,175		$ 4,684,528		$434,665		$1,657,926		$1,888,003
(2)	CapEx Reconciling Factors			($0.00148)		($0.00061)		($0.00138)		($0.00085)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-23	($277,278)	92,432,176	($136,800)	24,570,994	($14,988)	40,386,076	($55,733)	80,388,898	($68,331)
	Nov-23	($606,498)	204,049,146	($301,993)	53,987,946	($32,933)	86,596,772	($119,504)	174,837,917	($148,612)
	Dec-23	($651,680)	230,077,905	($340,515)	53,880,784	($32,867)	88,450,180	($122,061)	178,599,427	($151,810)
	Jan-24	($743,783)	277,908,357	($411,304)	60,009,074	($36,606)	98,860,158	($136,427)	183,064,155	($155,605)
	Feb-24	($685,531)	242,297,438	($358,600)	59,883,395	($36,529)	100,715,355	($138,987)	174,439,855	($148,274)
	Mar-24	($686,452)	231,704,413	($342,923)	61,382,696	($37,443)	106,715,629	($147,268)	187,878,826	($159,697)
	Apr-24	($646,324)	214,911,942	($318,070)	63,773,838	($38,902)	99,283,813	($137,012)	178,038,655	($151,333)
	May-24	($611,389)	196,741,787	($291,178)	58,259,578	($35,538)	94,423,094	($130,304)	179,329,490	($152,430)
	Jun-24	($692,881)	227,541,098	($336,761)	63,285,551	($38,604)	106,226,075	($146,592)	198,134,621	($168,414)
	Jul-24	$0	-	$0	-	$0	-	$0	-	$0
	Aug-24	$0	-	$0	-	$0	-	$0	-	$0
	Sep-24	$0	-	$0	-	$0	-	$0	-	$0
(4)	Oct-24	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	($5,601,816)		($2,838,144)		($304,410)		($1,133,888)		($1,304,506)
(6)	Ending Over/(Under) Recovery	$3,103,359		$1,846,384		$130,255		$524,038		$583,497

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		$34,150		$5,904
(2)	CapEx Reconciling Factors		($0.00090)		($0.00034)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-23	1,265,540	($1,139)	843,158	($287)
	Nov-23	2,964,561	($2,668)	2,317,257	($788)
	Dec-23	4,053,200	($3,648)	2,290,753	($779)
	Jan-24	3,540,882	($3,187)	1,923,642	($654)
	Feb-24	2,703,459	($2,433)	2,081,043	($708)
	Mar-24	(1,639,872)	$1,476	1,755,762	($597)
	Apr-24	371,502	($334)	1,979,932	($673)
	May-24	1,295,076	($1,166)	2,274,093	($773)
	Jun-24	1,998,323	($1,798)	2,095,397	($712)
	Jul-24	-	$0	-	$0
	Aug-24	-	$0	-	$0
	Sep-24	-	$0	-	$0
(4)	Oct-24	-	$0	-	$0
(5)	Total		($14,897)		($5,971)
(6)	Ending Over/(Under) Recovery		$19,253		($67)

(1) Docket No. 5209, Attachment TGS-2, Page 1 of 4, line (8)
(2) Docket No. 5209, Attachment TGS-2, Page 1 of 4, line (10)
(3) Prorated for usage on and after October 1, 2023
(4) Prorated for usage prior to October 1, 2024
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

(a) Sum of Column (b) from each rate
(b) From Company revenue report
(c) Column (b) x Line (2) CapEx Reconciling Factor

The Narragansett Electric Company
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Attachment TGS-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2023 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2024 ISR Plan
For the Recovery/(Refund) Period October 1, 2024 through September 30, 2025

	(a)	(b)
(1)	Actual FY 2024 O&M Revenue Requirement	$14,929,779
(2)	O&M Revenue Billed	$14,121,413
(3)	Total Over/(Under) Recovery for FY 2024	($808,366)
(4)	Remaining Over/(Under) For FY 2022	$0
(5)	Total Over/(Under) Recovery	($808,366)
(6)	Forecasted kWhs - October 1, 2024 through September 30, 2025	7,349,669,060
(7)	Proposed O&M Reconciling Factor Charge/(Credit) per kWh	$0.00010

(1) per Attachment TGS-1, Page 1, Line (1), Column (b)
(2) per Page 2
(3) Line (2) - Line (1)
(4) per Page 3, Line (4)
(5) Line (3) + Line (4)
(6) per Company forecast
(7) [Line (6) ÷ Line (7)] x -1, truncated to 5 decimal places

Fiscal Year 2023 Operations & Maintenance Reconciliation
For the Period April 1, 2023 through March 31, 2024
For the Recovery/Refund Period October 1, 2024 through September 30, 2025

O&M Factor Revenue:

	Month	O&M Revenue	Prior Period Reconciliation Factor Revenue	Base O&M Revenue
		(a)	(b)	(c)
(1)	Apr-23	$418,525	$0	$418,525
	May-23	$952,081	$0	$952,081
	Jun-23	$1,059,995	$0	$1,059,995
	Jul-23	$1,338,027	$0	$1,338,027
	Aug-23	$1,515,528	$0	$1,515,528
	Sep-23	$1,408,585	$0	$1,408,585
	Oct-23	$1,172,157	$38,382	$1,133,775
	Nov-23	$1,114,675	$83,961	$1,030,714
	Dec-23	$1,213,857	$89,176	$1,124,681
	Jan-24	$1,377,111	$100,049	$1,277,062
	Feb-24	$1,257,297	$93,139	$1,164,158
	Mar-24	$1,191,033	$94,048	$1,096,985
(2)	Apr-24	$653,253	51,956	$601,297
	Total	$14,672,124	$550,711	$14,121,413

(1) Reflects kWhs consumed on and after April 1
(2) Reflects kWhs consumed prior to April 1

(a) From monthly revenue reports
(b) per Page 3 and Page 4
(c) Column (a) - Column (b)

Fiscal Year 2022 O&M Reconciliation of Over Recovery
For the Period April 1, 2021 through March 31, 2022
For the Recovery/Refund Period October 1, 2022 through September 30, 2023

		Total	
(1)	Over/(Under) Recovery	$69,828	
(2)	O&M Reconciling Factor	$0.00000	
		Total kWhs (a)	Total Revenue (b)
(3)	Oct-22	240,167,576	$0
	Nov-22	529,423,899	$0
	Dec-22	557,826,589	$0
	Jan-23	624,530,528	$0
	Feb-23	541,220,679	$0
	Mar-23	569,558,756	$0
	Apr-23	572,384,448	$0
	May-23	517,822,669	$0
	Jun-23	543,735,753	$0
	Jul-23	681,209,423	$0
	Aug-23	762,998,742	$0
	Sep-23	700,002,294	$0
(4)	Oct-23	342,170,209	$0
(5)	Total	7,183,051,565	$0
(6)	Inclusion as Adjustment to FY 2023 O&M Reconciliation Balance		$69,828
(7)	Ending Over/(Under) Recovery		$0

(1) Docket No. 5098, Attachment PRB-3 page 1, line (5)
(2) Docket No. 5098, Attachment PRB-3 page 1, line (7)
(3) Reflects kWhs consumed on and after October 1
(4) Reflects kWhs consumed prior to October 1
(5) Sum of kWhs & revenue
(7) Line (1) + Line (5) - Line (6)

(a) per Company Records
(b) Line (2) x Column (a)

Fiscal Year 2023 O&M Reconciliation of Under Recovery
For the Period April 1, 2022 through March 31, 2023
For the Recovery/Refund Period October 1, 2023 through September 30, 2024

		Total	
(1)	Over/(Under) Recovery	($1,193,683)	
(2)	O&M Reconciling Factor	$0.00016	
		Total kWhs (a)	Total Revenue (b)
(3)	Oct-23	239,886,841	$38,382
	Nov-23	524,753,599	$83,961
	Dec-23	557,352,249	$89,176
	Jan-24	625,306,268	$100,049
	Feb-24	582,120,545	$93,139
	Mar-24	587,797,454	$94,048
	Apr-24	558,359,682	$89,338
	May-24	532,323,118	$85,172
	Jun-24	599,281,065	$95,885
	Jul-24	-	$0
	Aug-24	-	$0
	Sep-24	-	$0
(4)	Oct-24	-	$0
(5)	Total	4,807,180,821	$769,150
(6)	Ending Over/(Under) Recovery		($424,533)

(1) Docket No. 5209, Attachment TGS-3 page 1, line (6)
(2) Docket No. 5209, Attachment TGS-3 page 1, line (8)
(3) Reflects kWhs consumed on and after October 1
(4) Reflects kWhs consumed prior to October 1
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

(a) per Company Records
(b) Line (2) x Column (a)

Attachment TGS-4

Typical Bill Analysis

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

	Rates Effective July 1, 2024				Proposed Rates Effective October 1, 2024				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly 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	of Customers
(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)	(r)
150	$31.61	$15.57	$1.97	$49.15	$31.86	$15.57	$1.98	$49.41	$0.25	$0.00	$0.01	$0.26	0.5%	0.0%	0.0%	0.5%	30.1%
300	$52.41	$31.13	$3.48	$87.02	$52.91	$31.13	$3.50	$87.54	$0.50	$0.00	$0.02	$0.52	0.6%	0.0%	0.0%	0.6%	12.9%
400	$66.28	$41.51	$4.49	$112.28	$66.94	$41.51	$4.52	$112.97	$0.66	$0.00	$0.03	$0.69	0.6%	0.0%	0.0%	0.6%	11.6%
500	$80.15	$51.89	$5.50	$137.54	$80.97	$51.89	$5.54	$138.40	$0.82	$0.00	$0.04	$0.86	0.6%	0.0%	0.0%	0.6%	9.6%
600	$94.01	$62.26	$6.51	$162.78	$95.00	$62.26	$6.55	$163.81	$0.99	$0.00	$0.04	$1.03	0.6%	0.0%	0.0%	0.6%	7.7%
700	$107.88	$72.64	$7.52	$188.04	$109.03	$72.64	$7.57	$189.24	$1.15	$0.00	$0.05	$1.20	0.6%	0.0%	0.0%	0.6%	19.0%
1,200	$177.21	$124.52	$12.57	$314.30	$179.19	$124.52	$12.65	$316.36	$1.98	$0.00	$0.08	$2.06	0.6%	0.0%	0.0%	0.7%	6.8%
2,000	$288.15	$207.54	$20.65	$516.34	$291.45	$207.54	$20.79	$519.78	$3.30	$0.00	$0.14	$3.44	0.6%	0.0%	0.0%	0.7%	2.3%

			Rates Effective July 1, 2024 (s)	Proposed Rates Effective October 1, 2024 (t)	Line Item on Bill
(1)	Distribution Customer Charge		$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$4.02	$4.02	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge		$0.00227	$0.00227	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00016	$0.00010	
(7)	CapEx Factor Charge		$0.00709	$0.00709	
(8)	CapEx Reconciliation Factor		($0.00151)	$0.00020	
(9)	Revenue Decoupling Adjustment Factor		$0.00123	$0.00123	
(10)	Pension Adjustment Factor		($0.00274)	($0.00274)	
(11)	Storm Fund Replenishment Factor		$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor		$0.00009	$0.00009	
(13)	Performance Incentive Factor		$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor		$0.00277	$0.00277	
(15)	LRS Adjustment Factor (Rates Effective April 1, 2023)		$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge		$0.00980	$0.00980	Renewable Energy Distribution Charge
(17)	Net Metering Charge		$0.01253	$0.01253	
(18)	Base Transmission Charge		$0.03686	$0.03686	Transmission Charge
(19)	Transmission Adjustment Factor		$0.00421	$0.00421	
(20)	Transmission Uncollectible Factor		$0.00054	$0.00054	
(21)	Base Transition Charge		$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment		$0.00000	$0.00000	
(23)	Energy Efficiency Program Charge		$0.01169	$0.01169	Energy Efficiency Programs
(24)	Last Resort Service Base Charge		$0.08908	$0.08908	Supply Services Energy Charge
(25)	LRS Adjustment Factor		$0.00000	$0.00000	
(26)	LRS Adminstrative Cost Adjustment Factor		$0.00269	$0.00269	
(27)	Renewable Energy Standard Charge		$0.01200	$0.01200	
	Line Item on Bill				
(28)	Customer Charge		$6.00	$6.00	
(29)	LIHEAP Enhancement Charge		$0.79	$0.79	
(30)	RE Growth Program		$4.02	$4.02	
(31)	Transmission Charge	kWh x	$0.04161	$0.04161	
(32)	Distribution Energy Charge	kWh x	$0.06304	$0.06469	
(33)	Transition Charge	kWh x	$0.00000	$0.00000	
(34)	Energy Efficiency Programs	kWh x	$0.01169	$0.01169	
(35)	Renewable Energy Distribution Charge	kWh x	$0.02233	$0.02233	
(36)	Supply Services Energy Charge	kWh x	$0.10377	$0.10377	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024

Column (t): Line (6) per Attachment TGS-3, Page 1, Line (8). Line (8) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.

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

Monthly kWh	Rates Effective July 1, 2024						Proposed Rates Effective October 1, 2024						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	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	$31.20	$15.57	($11.69)	$35.08	$1.46	$36.54	$31.44	$15.57	($11.75)	$35.26	$1.47	$36.73	$0.18	$0.00	$0.01	$0.19	0.5%	0.0%	0.0%	0.5%	32.1%
300	$51.58	$31.13	($20.68)	$62.03	$2.58	$64.61	$52.08	$31.13	($20.80)	$62.41	$2.60	$65.01	$0.38	$0.00	$0.02	$0.40	0.6%	0.0%	0.0%	0.6%	15.4%
400	$65.17	$41.51	($26.67)	$80.01	$3.33	$83.34	$65.83	$41.51	($26.84)	$80.50	$3.35	$83.85	$0.49	$0.00	$0.02	$0.51	0.6%	0.0%	0.0%	0.6%	12.5%
500	$78.76	$51.89	($32.66)	$97.99	$4.08	$102.07	$79.59	$51.89	($32.87)	$98.61	$4.11	$102.72	$0.62	$0.00	$0.03	$0.65	0.6%	0.0%	0.0%	0.6%	9.6%
600	$92.35	$62.26	($38.65)	$115.96	$4.83	$120.79	$93.34	$62.26	($38.90)	$116.70	$4.86	$121.56	$0.74	$0.00	$0.03	$0.77	0.6%	0.0%	0.0%	0.6%	7.2%
700	$105.94	$72.64	($44.65)	$133.93	$5.58	$139.51	$107.10	$72.64	($44.94)	$134.80	$5.62	$140.42	$0.87	$0.00	$0.04	$0.91	0.6%	0.0%	0.0%	0.7%	16.4%
1,200	$173.89	$124.52	($74.60)	$223.81	$9.33	$233.14	$175.87	$124.52	($75.10)	$225.29	$9.39	$234.68	$1.48	$0.00	$0.06	$1.54	0.6%	0.0%	0.0%	0.7%	5.2%
2,000	$282.61	$207.54	($122.54)	$367.61	$15.32	$382.93	$285.91	$207.54	($123.36)	$370.09	$15.42	$385.51	$2.48	$0.00	$0.10	$2.58	0.6%	0.0%	0.0%	0.7%	1.6%

		Rates Effective July 1, 2024 (w)	Proposed Rates Effective October 1, 2024 (x)	Line Item on Bill
(1)	Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$4.02	$4.02	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge	$0.00227	$0.00227	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00016	$0.00010	
(7)	CapEx Factor Charge	$0.00709	$0.00709	
(8)	CapEx Reconciliation Factor	($0.00151)	$0.00020	
(9)	Revenue Decoupling Adjustment Factor	$0.00123	$0.00123	
(10)	Pension Adjustment Factor	($0.00274)	($0.00274)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00009	$0.00009	
(13)	Performance Incentive Factor	$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00980	$0.00980	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.01253	$0.01253	
(18)	Base Transmission Charge	$0.03686	$0.03686	Transmission Charge
(19)	Transmission Adjustment Factor	$0.00421	$0.00421	
(20)	Transmission Uncollectible Factor	$0.00054	$0.00054	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00000	$0.00000	
(23)	Energy Efficiency Program Charge	$0.01169	$0.01169	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08908	$0.08908	Supply Services Energy Charge
(25)	LRS Adjustment Factor	$0.00000	$0.00000	
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00269	$0.00269	
(27)	Renewable Energy Standard Charge	$0.01200	$0.01200	
	Line Item on Bill			
(28)	Customer Charge	$6.00	$6.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$4.02	$4.02	
(31)	Transmission Charge	$0.04161	$0.04161	
(32)	Distribution Energy Charge	$0.06027	$0.06192	
(33)	Transition Charge	$0.00000	$0.00000	
(34)	Energy Efficiency Programs	$0.01169	$0.01169	
(35)	Renewable Energy Distribution Charge	$0.02233	$0.02233	
(36)	Supply Services Energy Charge	$0.10377	$0.10377	
(37)	Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024
Column (x): Line (6) per Attachment TGS-3, Page 1, Line (8). Line (8) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.

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

	Rates Effective July 1, 2024						Proposed Rates Effective October 1, 2024						$ 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	$31.20	$15.57	($14.03)	$32.74	$1.36	$34.10	$31.44	$15.57	($14.10)	$32.91	$1.37	$34.28	$0.17	$0.00	$0.01	$0.18	0.5%	0.0%	0.0%	0.5%	32.1%
300	$51.58	$31.13	($24.81)	$57.90	$2.41	$60.31	$52.08	$31.13	($24.96)	$58.25	$2.43	$60.68	$0.35	$0.00	$0.02	$0.37	0.6%	0.0%	0.0%	0.6%	15.4%
400	$65.17	$41.51	($32.00)	$74.68	$3.11	$77.79	$65.83	$41.51	($32.20)	$75.14	$3.13	$78.27	$0.46	$0.00	$0.02	$0.48	0.6%	0.0%	0.0%	0.6%	12.5%
500	$78.76	$51.89	($39.20)	$91.45	$3.81	$95.26	$79.59	$51.89	($39.44)	$92.04	$3.84	$95.88	$0.59	$0.00	$0.03	$0.62	0.6%	0.0%	0.0%	0.7%	9.6%
600	$92.35	$62.26	($46.38)	$108.23	$4.51	$112.74	$93.34	$62.26	($46.68)	$108.92	$4.54	$113.46	$0.69	$0.00	$0.03	$0.72	0.6%	0.0%	0.0%	0.6%	7.2%
700	$105.94	$72.64	($53.57)	$125.01	$5.21	$130.22	$107.10	$72.64	($53.92)	$125.82	$5.24	$131.06	$0.81	$0.00	$0.03	$0.84	0.6%	0.0%	0.0%	0.6%	16.4%
1,200	$173.89	$124.52	($89.52)	$208.89	$8.70	$217.59	$175.87	$124.52	($90.12)	$210.27	$8.76	$219.03	$1.38	$0.00	$0.06	$1.44	0.6%	0.0%	0.0%	0.7%	5.2%
2,000	$282.61	$207.54	($147.05)	$343.10	$14.30	$357.40	$285.91	$207.54	($148.04)	$345.41	$14.39	$359.80	$2.31	$0.00	$0.09	$2.40	0.6%	0.0%	0.0%	0.7%	1.6%

		Rates Effective July 1, 2024 (w)	Proposed Rates Effective October 1, 2024 (x)	Line Item on Bill
(1)	Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$4.02	$4.02	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge	$0.00227	$0.00227	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00016	$0.00010	
(7)	CapEx Factor Charge	$0.00709	$0.00709	
(8)	CapEx Reconciliation Factor	($0.00151)	$0.00020	
(9)	Revenue Decoupling Adjustment Factor	$0.00123	$0.00123	
(10)	Pension Adjustment Factor	($0.00274)	($0.00274)	Distribution Energy Charge
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00009	$0.00009	
(13)	Performance Incentive Factor	$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00980	$0.00980	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.01253	$0.01253	
(18)	Base Transmission Charge	$0.03686	$0.03686	
(19)	Transmission Adjustment Factor	$0.00421	$0.00421	Transmission Charge
(20)	Transmission Uncollectible Factor	$0.00054	$0.00054	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00000	$0.00000	
(23)	Energy Efficiency Program Charge	$0.01169	$0.01169	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08908	$0.08908	
(25)	LRS Adjustment Factor	$0.00000	$0.00000	Supply Services Energy Charge
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00269	$0.00269	
(27)	Renewable Energy Standard Charge	$0.01200	$0.01200	
	Line Item on Bill			
(28)	Customer Charge	$6.00	$6.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$4.02	$4.02	
(31)	Transmission Charge	$0.04161	$0.04161	
(32)	Distribution Energy Charge	$0.06027	$0.06192	
(33)	Transition Charge	$0.00000	$0.00000	
(34)	Energy Efficiency Programs	$0.01169	$0.01169	
(35)	Renewable Energy Distribution Charge	$0.02233	$0.02233	
(36)	Supply Services Energy Charge	$0.10377	$0.10377	
(37)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024

Column (x): Line (6) per Attachment TGS-3, Page 1, Line (8). Line (8) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.

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

	Rates Effective July 1, 2024				Proposed Rates Effective October 1, 2024				$ 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	$46.58	$24.66	$2.97	$74.21	$46.93	$24.66	$2.98	$74.57	$0.35	$0.00	$0.01	$0.36	0.5%	0.0%	0.0%	0.5%	56.3%
500	$76.19	$49.32	$5.23	$130.74	$76.88	$49.32	$5.26	$131.46	$0.69	$0.00	$0.03	$0.72	0.5%	0.0%	0.0%	0.6%	16.9%
1,000	$135.39	$98.64	$9.75	$243.78	$136.78	$98.64	$9.81	$245.23	$1.39	$0.00	$0.06	$1.45	0.6%	0.0%	0.0%	0.6%	8.1%
1,500	$194.60	$147.96	$14.27	$356.83	$196.68	$147.96	$14.36	$359.00	$2.08	$0.00	$0.09	$2.17	0.6%	0.0%	0.0%	0.6%	5.0%
2,000	$253.80	$197.28	$18.80	$469.88	$256.58	$197.28	$18.91	$472.77	$2.78	$0.00	$0.11	$2.89	0.6%	0.0%	0.0%	0.6%	13.6%

	Rates Effective July 1, 2024 (s)	Proposed Rates Effective October 1, 2024 (t)	Line Item on Bill
(1) Distribution Customer Charge	$10.00	$10.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$6.19	$6.19	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04482	$0.04482	
(5) Operating & Maintenance Expense Charge	$0.00223	$0.00223	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00016	$\boxed{\$0.00010}$	
(7) CapEx Factor Charge	$0.00595	$0.00595	
(8) CapEx Reconciliation Factor	($0.00064)	$\boxed{\$0.00081}$	
(9) Revenue Decoupling Adjustment Factor	$0.00123	$0.00123	Distribution Energy Charge
(10) Pension Adjustment Factor	($0.00274)	($0.00274)	
(11) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12) Arrearage Management Adjustment Factor	$0.00009	$0.00009	
(13) Performance Incentive Factor	$0.00000	$0.00000	
(14) Low Income Discount Recovery Factor	$0.00277	$0.00277	
(15) LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00000	$0.00000	
(16) Long-term Contracting for Renewable Energy Charge	$0.00980	$0.00980	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.01253	$0.01253	
(18) Base Transmission Charge	$0.02668	$0.02668	
(19) Transmission Adjustment Factor	($0.00427)	($0.00427)	Transmission Charge
(20) Transmission Uncollectible Factor	$0.00023	$0.00023	
(21) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22) Transition Adjustment	$0.00000	$0.00000	
(23) Energy Efficiency Program Charge	$0.01169	$0.01169	Energy Efficiency Programs
(24) Last Resort Service Base Charge	$0.08353	$0.08353	
(25) LRS Adjustment Factor	$0.00000	$0.00000	Supply Services Energy Charge
(26) LRS Adminstrative Cost Adjustment Factor	$0.00311	$0.00311	
(27) Renewable Energy Standard Charge	$0.01200	$0.01200	
Line Item on Bill			
(28) Customer Charge	$10.00	$10.00	
(29) LIHEAP Enhancement Charge	$0.79	$0.79	
(30) RE Growth Program	$6.19	$6.19	
(31) Transmission Charge	$0.02264	$0.02264	
(32) Distribution Energy Charge	$0.06175	$\boxed{\$0.06314}$	
(33) Transition Charge	$0.00000	$0.00000	
(34) Energy Efficiency Programs	$0.01169	$0.01169	
(35) Renewable Energy Distribution Charge	$0.02233	$0.02233	
(36) Supply Services Energy Charge	$0.09864	$0.09864	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024

Column (t): Line (6) per Attachment TGS-3, Page 1, Line (8). Line (8) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.

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

			Rates Effective July 1, 2024				Proposed Rates Effective October 1, 2024				$ 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)
20	200	4,000	$621.24	$394.56	$42.33	$1,058.13	$625.64	$394.56	$42.51	$1,062.71	$4.40	$0.00	$0.18	$4.58	0.4%	0.0%	0.0%	0.4%
50	200	10,000	$1,371.54	$986.40	$98.25	$2,456.19	$1,382.54	$986.40	$98.71	$2,467.65	$11.00	$0.00	$0.46	$11.46	0.4%	0.0%	0.0%	0.5%
100	200	20,000	$2,622.04	$1,972.80	$191.45	$4,786.29	$2,644.04	$1,972.80	$192.37	$4,809.21	$22.00	$0.00	$0.92	$22.92	0.5%	0.0%	0.0%	0.5%
150	200	30,000	$3,872.54	$2,959.20	$284.66	$7,116.40	$3,905.54	$2,959.20	$286.03	$7,150.77	$33.00	$0.00	$1.37	$34.37	0.5%	0.0%	0.0%	0.5%
20	300	6,000	$732.84	$591.84	$55.20	$1,379.88	$739.44	$591.84	$55.47	$1,386.75	$6.60	$0.00	$0.27	$6.87	0.5%	0.0%	0.0%	0.5%
50	300	15,000	$1,650.54	$1,479.60	$130.42	$3,260.56	$1,667.04	$1,479.60	$131.11	$3,277.75	$16.50	$0.00	$0.69	$17.19	0.5%	0.0%	0.0%	0.5%
100	300	30,000	$3,180.04	$2,959.20	$255.80	$6,395.04	$3,213.04	$2,959.20	$257.18	$6,429.42	$33.00	$0.00	$1.38	$34.38	0.5%	0.0%	0.0%	0.5%
150	300	45,000	$4,709.54	$4,438.80	$381.18	$9,529.52	$4,759.04	$4,438.80	$383.24	$9,581.08	$49.50	$0.00	$2.06	$51.56	0.5%	0.0%	0.0%	0.5%
20	400	8,000	$844.44	$789.12	$68.07	$1,701.63	$853.24	$789.12	$68.43	$1,710.79	$8.80	$0.00	$0.36	$9.16	0.5%	0.0%	0.0%	0.5%
50	400	20,000	$1,929.54	$1,972.80	$162.60	$4,064.94	$1,951.54	$1,972.80	$163.51	$4,087.85	$22.00	$0.00	$0.91	$22.91	0.5%	0.0%	0.0%	0.6%
100	400	40,000	$3,738.04	$3,945.60	$320.15	$8,003.79	$3,782.04	$3,945.60	$321.99	$8,049.63	$44.00	$0.00	$1.84	$45.84	0.5%	0.0%	0.0%	0.6%
150	400	60,000	$5,546.54	$5,918.40	$477.71	$11,942.65	$5,612.54	$5,918.40	$480.46	$12,011.40	$66.00	$0.00	$2.75	$68.75	0.6%	0.0%	0.0%	0.6%
20	500	10,000	$956.04	$986.40	$80.94	$2,023.38	$967.04	$986.40	$81.39	$2,034.83	$11.00	$0.00	$0.45	$11.45	0.5%	0.0%	0.0%	0.6%
50	500	25,000	$2,208.54	$2,466.00	$194.77	$4,869.31	$2,236.04	$2,466.00	$195.92	$4,897.96	$27.50	$0.00	$1.15	$28.65	0.6%	0.0%	0.0%	0.6%
100	500	50,000	$4,296.04	$4,932.00	$384.50	$9,612.54	$4,351.04	$4,932.00	$386.79	$9,669.83	$55.00	$0.00	$2.29	$57.29	0.6%	0.0%	0.0%	0.6%
150	500	75,000	$6,383.54	$7,398.00	$574.23	$14,355.77	$6,466.04	$7,398.00	$577.67	$14,441.71	$82.50	$0.00	$3.44	$85.94	0.6%	0.0%	0.0%	0.6%
20	600	12,000	$1,067.64	$1,183.68	$93.81	$2,345.13	$1,080.84	$1,183.68	$94.36	$2,358.88	$13.20	$0.00	$0.55	$13.75	0.6%	0.0%	0.0%	0.6%
50	600	30,000	$2,487.54	$2,959.20	$226.95	$5,673.69	$2,520.54	$2,959.20	$228.32	$5,708.06	$33.00	$0.00	$1.37	$34.37	0.6%	0.0%	0.0%	0.6%
100	600	60,000	$4,854.04	$5,918.40	$448.85	$11,221.29	$4,920.04	$5,918.40	$451.60	$11,290.04	$66.00	$0.00	$2.75	$68.75	0.6%	0.0%	0.0%	0.6%
150	600	90,000	$7,220.54	$8,877.60	$670.76	$16,768.90	$7,319.54	$8,877.60	$674.88	$16,872.02	$99.00	$0.00	$4.12	$103.12	0.6%	0.0%	0.0%	0.6%

		Rates Effective July 1, 2024	Proposed Rates Effective October 1, 2024	Line Item on Bill
		(r)	(s)	
(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	$63.55	$63.55	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)	$1.93	$1.93	
(6)	Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00201	$0.00201	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00016	$\boxed{\$0.00010}$	
(9)	CapEx Reconciliation Factor	($0.00140)	$\boxed{(\$0.00024)}$	
(10)	Revenue Decoupling Adjustment Factor	$0.00123	$0.00123	
(11)	Pension Adjustment Factor	($0.00274)	($0.00274)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00009	$0.00009	
(14)	Performance Incentive Factor	$0.00000	$0.00000	
(15)	Low Income Discount Recovery Factor	$0.00277	$0.00277	
(16)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00000	$0.00000	
(17)	Long-term Contracting for Renewable Energy Charge	$0.00980	$0.00980	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.01253	$0.01253	
(19)	Transmission Demand Charge	$5.02	$5.02	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01007	$0.01007	Transmission Adjustment
(21)	Transmission Adjustment Factor	($0.00338)	($0.00338)	
(22)	Transmission Uncollectible Factor	$0.00033	$0.00033	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00000	$0.00000	
(25)	Energy Efficiency Program Charge	$0.01169	$0.01169	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.08353	$0.08353	Supply Services Energy Charge
(27)	LRS Adjustment Factor	$0.00000	$0.00000	
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00311	$0.00311	
(29)	Renewable Energy Standard Charge	$0.01200	$0.01200	

	Line Item on Bill		
(30)	Customer Charge	$145.00	$145.00
(32)	LIHEAP Enhancement Charge	$0.79	$0.79
(31)	RE Growth Program	$63.55	$63.55
(33)	Transmission Adjustment	$0.00702	$0.00702
(34)	Distribution Energy Charge	$0.01476	$\boxed{\$0.01586}$
(35)	Distribution Demand Charge	$8.83	$8.83
(36)	Transmission Demand Charge	$5.02	$5.02
(35)	Transition Charge	$0.00000	$0.00000
(36)	Energy Efficiency Programs	$0.01169	$0.01169
(37)	Renewable Energy Distribution Charge	$0.02233	$0.02233
(38)	Supply Services Energy Charge	$0.09864	$0.09864

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024
Column (s): Line (8) per Attachment TGS-3, Page 1, Line (8). Line (9) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.

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

			Rates Effective July 1, 2024				Proposed Rates Effective October 1, 2024				$ 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)
200	200	40,000	$5,276.86	$3,525.47	$366.76	$9,169.09	$5,296.06	$3,525.47	$367.56	$9,189.09	$19.20	$0.00	$0.80	$20.00	0.2%	0.0%	0.0%	0.2%
750	200	150,000	$19,288.66	$13,220.50	$1,354.55	$33,863.71	$19,360.66	$13,220.50	$1,357.55	$33,938.71	$72.00	$0.00	$3.00	$75.00	0.2%	0.0%	0.0%	0.2%
1,000	200	200,000	$25,657.66	$17,627.33	$1,803.54	$45,088.53	$25,753.66	$17,627.33	$1,807.54	$45,188.53	$96.00	$0.00	$4.00	$100.00	0.2%	0.0%	0.0%	0.2%
1,500	200	300,000	$38,395.66	$26,441.00	$2,701.53	$67,538.19	$38,539.66	$26,441.00	$2,707.53	$67,688.19	$144.00	$0.00	$6.00	$150.00	0.2%	0.0%	0.0%	0.2%
2,500	200	500,000	$63,871.66	$44,068.33	$4,497.50	$112,437.49	$64,111.66	$44,068.33	$4,507.50	$112,687.49	$240.00	$0.00	$10.00	$250.00	0.2%	0.0%	0.0%	0.2%
5,000	200	1,000,000	$127,561.66	$88,136.67	$8,987.43	$224,685.76	$128,041.66	$88,136.67	$9,007.43	$225,185.76	$480.00	$0.00	$20.00	$500.00	0.2%	0.0%	0.0%	0.2%
7,500	200	1,500,000	$191,251.66	$132,205.00	$13,477.36	$336,934.02	$191,971.66	$132,205.00	$13,507.36	$337,684.02	$720.00	$0.00	$30.00	$750.00	0.2%	0.0%	0.0%	0.2%
10,000	200	2,000,000	$254,941.66	$176,273.33	$17,967.29	$449,182.28	$255,901.66	$176,273.33	$18,007.29	$450,182.28	$960.00	$0.00	$40.00	$1,000.00	0.2%	0.0%	0.0%	0.2%
20,000	200	4,000,000	$509,701.66	$352,546.67	$35,927.02	$898,175.35	$511,621.66	$352,546.67	$36,007.02	$900,175.35	$1,920.00	$0.00	$80.00	$2,000.00	0.2%	0.0%	0.0%	0.2%
200	300	60,000	$6,521.46	$5,288.20	$492.07	$12,301.73	$6,550.26	$5,288.20	$493.27	$12,331.73	$28.80	$0.00	$1.20	$30.00	0.2%	0.0%	0.0%	0.2%
750	300	225,000	$23,955.91	$19,830.75	$1,824.44	$45,611.10	$24,063.91	$19,830.75	$1,828.94	$45,723.60	$108.00	$0.00	$4.50	$112.50	0.2%	0.0%	0.0%	0.2%
1,000	300	300,000	$31,880.66	$26,441.00	$2,430.07	$60,751.73	$32,024.66	$26,441.00	$2,436.07	$60,901.73	$144.00	$0.00	$6.00	$150.00	0.2%	0.0%	0.0%	0.2%
1,500	300	450,000	$47,730.16	$39,661.50	$3,641.32	$91,032.98	$47,946.16	$39,661.50	$3,650.32	$91,257.98	$216.00	$0.00	$9.00	$225.00	0.2%	0.0%	0.0%	0.2%
2,500	300	750,000	$79,429.16	$66,102.50	$6,063.82	$151,595.48	$79,789.16	$66,102.50	$6,078.82	$151,970.48	$360.00	$0.00	$15.00	$375.00	0.2%	0.0%	0.0%	0.2%
5,000	300	1,500,000	$158,676.66	$132,205.00	$12,120.07	$303,001.73	$159,396.66	$132,205.00	$12,150.07	$303,751.73	$720.00	$0.00	$30.00	$750.00	0.2%	0.0%	0.0%	0.2%
7,500	300	2,250,000	$237,924.16	$198,307.50	$18,176.32	$454,407.98	$239,004.16	$198,307.50	$18,221.32	$455,532.98	$1,080.00	$0.00	$45.00	$1,125.00	0.2%	0.0%	0.0%	0.2%
10,000	300	3,000,000	$317,171.66	$264,410.00	$24,232.57	$605,814.23	$318,611.66	$264,410.00	$24,292.57	$607,314.23	$1,440.00	$0.00	$60.00	$1,500.00	0.2%	0.0%	0.0%	0.2%
20,000	300	6,000,000	$634,161.66	$528,820.00	$48,457.57	$1,211,439.23	$637,041.66	$528,820.00	$48,577.57	$1,214,439.23	$2,880.00	$0.00	$120.00	$3,000.00	0.2%	0.0%	0.0%	0.2%
200	400	80,000	$7,766.06	$7,050.93	$617.37	$15,434.36	$7,804.46	$7,050.93	$618.97	$15,474.36	$38.40	$0.00	$1.60	$40.00	0.2%	0.0%	0.0%	0.3%
750	400	300,000	$28,623.16	$26,441.00	$2,294.34	$57,358.50	$28,767.16	$26,441.00	$2,300.34	$57,508.50	$144.00	$0.00	$6.00	$150.00	0.3%	0.0%	0.0%	0.3%
1,000	400	400,000	$38,103.66	$35,254.67	$3,056.60	$76,414.93	$38,295.66	$35,254.67	$3,064.60	$76,614.93	$192.00	$0.00	$8.00	$200.00	0.3%	0.0%	0.0%	0.3%
1,500	400	600,000	$57,064.66	$52,882.00	$4,581.11	$114,527.77	$57,352.66	$52,882.00	$4,593.11	$114,827.77	$288.00	$0.00	$12.00	$300.00	0.3%	0.0%	0.0%	0.3%
2,500	400	1,000,000	$94,986.66	$88,136.67	$7,630.14	$190,753.47	$95,466.66	$88,136.67	$7,650.14	$191,253.47	$480.00	$0.00	$20.00	$500.00	0.3%	0.0%	0.0%	0.3%
5,000	400	2,000,000	$189,791.66	$176,273.33	$15,252.71	$381,317.70	$190,751.66	$176,273.33	$15,292.71	$382,317.70	$960.00	$0.00	$40.00	$1,000.00	0.3%	0.0%	0.0%	0.3%
7,500	400	3,000,000	$284,596.66	$264,410.00	$22,875.28	$571,881.94	$286,036.66	$264,410.00	$22,935.28	$573,381.94	$1,440.00	$0.00	$60.00	$1,500.00	0.3%	0.0%	0.0%	0.3%
10,000	400	4,000,000	$379,401.66	$352,546.67	$30,497.85	$762,446.18	$381,321.66	$352,546.67	$30,577.85	$764,446.18	$1,920.00	$0.00	$80.00	$2,000.00	0.3%	0.0%	0.0%	0.3%
20,000	400	8,000,000	$758,621.66	$705,093.33	$60,988.13	$1,524,703.12	$762,461.66	$705,093.33	$61,148.13	$1,528,703.12	$3,840.00	$0.00	$160.00	$4,000.00	0.3%	0.0%	0.0%	0.3%
200	500	100,000	$9,010.66	$8,813.67	$742.68	$18,567.01	$9,058.66	$8,813.67	$744.68	$18,617.01	$48.00	$0.00	$2.00	$50.00	0.3%	0.0%	0.0%	0.3%
750	500	375,000	$33,290.41	$33,051.25	$2,764.24	$69,105.90	$33,470.41	$33,051.25	$2,771.74	$69,293.40	$180.00	$0.00	$7.50	$187.50	0.3%	0.0%	0.0%	0.3%
1,000	500	500,000	$44,326.66	$44,068.33	$3,683.12	$92,078.11	$44,566.66	$44,068.33	$3,693.12	$92,328.11	$240.00	$0.00	$10.00	$250.00	0.3%	0.0%	0.0%	0.3%
1,500	500	750,000	$66,399.16	$66,102.50	$5,520.90	$138,022.56	$66,759.16	$66,102.50	$5,535.90	$138,397.56	$360.00	$0.00	$15.00	$375.00	0.3%	0.0%	0.0%	0.3%
2,500	500	1,250,000	$110,544.16	$110,170.83	$9,196.46	$229,911.45	$111,144.16	$110,170.83	$9,221.46	$230,536.45	$600.00	$0.00	$25.00	$625.00	0.3%	0.0%	0.0%	0.3%
5,000	500	2,500,000	$220,906.66	$220,341.67	$18,385.35	$459,633.68	$222,106.66	$220,341.67	$18,435.35	$460,883.68	$1,200.00	$0.00	$50.00	$1,250.00	0.3%	0.0%	0.0%	0.3%
7,500	500	3,750,000	$331,269.16	$330,512.50	$27,574.24	$689,355.90	$333,069.16	$330,512.50	$27,649.24	$691,230.90	$1,800.00	$0.00	$75.00	$1,875.00	0.3%	0.0%	0.0%	0.3%
10,000	500	5,000,000	$441,631.66	$440,683.33	$36,763.13	$919,078.12	$444,031.66	$440,683.33	$36,863.13	$921,578.12	$2,400.00	$0.00	$100.00	$2,500.00	0.3%	0.0%	0.0%	0.3%
20,000	500	10,000,000	$883,081.66	$881,366.67	$73,518.69	$1,837,967.02	$887,881.66	$881,366.67	$73,718.69	$1,842,967.02	$4,800.00	$0.00	$200.00	$5,000.00	0.3%	0.0%	0.0%	0.3%
200	600	120,000	$10,255.26	$10,576.40	$867.99	$21,699.65	$10,312.86	$10,576.40	$870.39	$21,759.65	$57.60	$0.00	$2.40	$60.00	0.3%	0.0%	0.0%	0.3%
750	600	450,000	$37,957.66	$39,661.50	$3,234.13	$80,853.29	$38,173.66	$39,661.50	$3,243.13	$81,078.29	$216.00	$0.00	$9.00	$225.00	0.3%	0.0%	0.0%	0.3%
1,000	600	600,000	$50,549.66	$52,882.00	$4,309.65	$107,741.31	$50,837.66	$52,882.00	$4,321.65	$108,041.31	$288.00	$0.00	$12.00	$300.00	0.3%	0.0%	0.0%	0.3%
1,500	600	900,000	$75,733.66	$79,323.00	$6,460.69	$161,517.35	$76,165.66	$79,323.00	$6,478.69	$161,967.35	$432.00	$0.00	$18.00	$450.00	0.3%	0.0%	0.0%	0.3%
2,500	600	1,500,000	$126,101.66	$132,205.00	$10,762.78	$269,069.44	$126,821.66	$132,205.00	$10,792.78	$269,819.44	$720.00	$0.00	$30.00	$750.00	0.3%	0.0%	0.0%	0.3%
5,000	600	3,000,000	$252,021.66	$264,410.00	$21,517.99	$537,949.65	$253,461.66	$264,410.00	$21,577.99	$539,449.65	$1,440.00	$0.00	$60.00	$1,500.00	0.3%	0.0%	0.0%	0.3%
7,500	600	4,500,000	$377,941.66	$396,615.00	$32,273.20	$806,829.86	$380,101.66	$396,615.00	$32,363.20	$809,079.86	$2,160.00	$0.00	$90.00	$2,250.00	0.3%	0.0%	0.0%	0.3%
10,000	600	6,000,000	$503,861.66	$528,820.00	$43,028.41	$1,075,710.07	$506,741.66	$528,820.00	$43,148.41	$1,078,710.07	$2,880.00	$0.00	$120.00	$3,000.00	0.3%	0.0%	0.0%	0.3%
20,000	600	12,000,000	$1,007,541.66	$1,057,640.00	$86,049.24	$2,151,230.90	$1,013,301.66	$1,057,640.00	$86,289.24	$2,157,230.90	$5,760.00	$0.00	$240.00	$6,000.00	0.3%	0.0%	0.0%	0.3%

		Rates Effective July 1, 2024 (r)	Proposed Rates Effective October 1, 2024 (s)	Line Item on Bill
(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	$522.87	$522.87	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)	$1.91	$1.91	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	
(7)	Operating & Maintenance Expense Charge	$0.00101	$0.00101	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00016	$0.00010	
(9)	CapEx Reconciliation Factor	($0.00086)	($0.00032)	
(10)	Revenue Decoupling Adjustment Factor	$0.00123	$0.00123	
(11)	Pension Adjustment Factor	($0.00274)	($0.00274)	Distribution Energy Charge
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00009	$0.00009	
(14)	Performance Incentive Factor	$0.00000	$0.00000	
(15)	Low Income Discount Recovery Factor	$0.00277	$0.00277	
(16)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00000	$0.00000	
(17)	Long-term Contracting for Renewable Energy Charge	$0.00980	$0.00980	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.01253	$0.01253	
(19)	Transmission Demand Charge	$5.82	$5.82	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01288	$0.01288	
(21)	Transmission Adjustment Factor	$0.00109	$0.00109	Transmission Adjustment
(22)	Transmission Uncollectible Factor	$0.00040	$0.00040	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00000	$0.00000	
(25)	Energy Efficiency Program Charge	$0.01169	$0.01169	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.07277	$0.07277	
(27)	LRS Adjustment Factor	$0.00000	$0.00000	Supply Services Energy Charge
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00337	$0.00337	
(29)	Renewable Energy Standard Charge	$0.01200	$0.01200	
	Line Item on Bill			
(30)	Customer Charge	$1,100.00	$1,100.00	
(31)	LIHEAP Enhancement Charge	$0.79	$0.79	
(32)	RE Growth Program	$522.87	$522.87	
(33)	Transmission Adjustment	$0.01437	$0.01437	
(34)	Distribution Energy Charge	$0.01384	$0.01432	
(35)	Distribution Demand Charge	$7.21	$7.21	
(36)	Transmission Demand Charge	$5.82	$5.82	
(35)	Transition Charge	$0.00000	$0.00000	
(36)	Energy Efficiency Programs	$0.01169	$0.01169	
(37)	Renewable Energy Distribution Charge	$0.02233	$0.02233	
(38)	Supply Services Energy Charge	$0.08814	$0.08814	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2024
Column (s): Line (8) per Attachment TGS-3, Page 1, Line (8). Line (9) per Attachment TGS-2, Page 1, Line (10). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2024, and Summary of Rates Last Res
Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2024.