Rhode Island Energy

The Narragansett Electric Company

FY 2025 Electric Infrastructure, Safety and Reliability Plan

Annual Reconciliation

August 1, 2025

Docket No. 23-48-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, 2025

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. 23-48-EL - FY 2025 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") 2025[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 Eric J. Wiesner** – The testimony of Mr. Wiesner presents the Filing in relation to the FY 2025 Electric ISR Plan which was approved by the PUC in this docket. Attachment EJW-1, which is attached to Mr. Wiesner's testimony, includes an Executive Summary, FY 2025 Plant in Service Additions, FY 2025 Capital Spending Summary, FY 2025 Capital Spending by Key Driver Category, FY 2025 Vegetation Management ("VM"), FY 2025 Other Operations and Maintenance ("O&M"), Reliability Performance, and updated Five Year Investment Plan. Please note that the Company is continuing to review data on Customers Experiencing Multiple Interruptions and will provide a report as soon as it is available. See below for a FY 2025 budget vs actuals summary:

Item	Target/Budget	Actual
Plant in Service Additions	$100.1M	$115.1M
Cost of Removal Spending	$19.3M	$22.7M
Capital Spending	$179.8M	$189.5M
O&M Spending	$14.1M	$13.9M

* Figures above do not factor in spending on Advanced Metering Functionality.

[1] FY 2025 was April 1, 2024 through March 31, 2025.

- **<u>Pre-Filed Direct Testimony of Jeffrey D. Oliveira</u>** – The testimony of Mr. Oliveira describes the calculation of the revenue requirement. The revenue requirement totals $59,064,126. This is an increase of $4,202,244 from the projected FY 2025 Electric ISR revenue requirement of $54,861,882, previously approved by the PUC in this docket.

  In compliance with PUC Order No. 25178, ¶ 2, issued in Docket No. 23-48-EL, the revenue requirement noted above includes a downward adjustment totaling $937,813 due to the Company's FY 2025 overspend. It also includes tax related adjustments as described in Ms. Hawk's testimony.

- **<u>Pre-Filed Direct Testimony of Natalie Hawk</u>** – The testimony of Ms. Hawk describes tax related adjustments to the revenue requirement including FY 2025 tax updates used to calculate accumulated deferred income taxes ("ADIT"), FY 2023 and FY 2024 tax updates which resulted in "true-ups" to the revenue requirement, FY 2023 and FY 2024 revenue requirement adjustments for tax related formula corrections to the FY 2018 and FY 2019 vintage years, and hold harmless adjustments.

- **<u>Pre-Filed Direct Testimony of Tyler G. Shields</u>** – 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 2025 ISR Plan. The impact of the proposed CapEx Reconciling Factor of $0.00095 per kWh and the proposed O&M Reconciling Factor of $0.00004 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is an increase of $0.42, or approximately 0.3%, from $138.80 to $139.22.

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. 23-48-EL Service List

PRE-FILED DIRECT TESTIMONY

OF

ERIC J. WIESNER

August 1, 2025

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I. Introduction and Qualifications

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

A. My name is Eric Wiesner. My business address is 280 Melrose Street, Providence Rhode Island 02907.

Q. Mr. Wiesner, 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 Director of Asset Management and Engineering. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

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

A. I received a Bachelor of Science degree in Electric Engineering from Virginia Polytechnic Institute and State University (Virginia Tech) in Blacksburg, Virginia, in 2009 and a Master of Engineering in Electrical and Computer Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts, in 2015. I am a Registered Professional Engineer in Rhode Island, number 14219. I worked at American Power Conversion from 2009 to 2010, after which time I joined National Grid USA Service Company, Inc. (the "Service Company"). From 2010 to 2012, I worked in Distribution Design supporting distribution line capital projects and programs. From 2012 to 2015, I worked in Substation Engineering supporting capital projects such as substation rebuilds, greenfield substations, and responding to equipment failures. From 2015 to 2016, I joined General Dynamics Electric Boat as an Engineer supporting the electrical power system on various submarines. I returned to the Service Company in 2016 and rejoined the Substation Engineering department. From 2016 to 2020, I worked in Substation Operations and Maintenance as a field supervisor where I oversaw the day-to-day operations and maintenance of substations in Central Massachusetts. From 2020 to 2022, I was the Manager of Substation Engineering where I oversaw the execution of substation capital projects and programs. In 2022, I joined Rhode Island Energy as the Regional Engineering Manager where I was responsible for overseeing the implementation of substation and distribution line capital projects, field support, transmission line inspection and maintenance, street lighting, and contact voltage monitoring. In 2024, I was promoted to my current position as the Director of Asset Management and Engineering.

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

A. Yes, I testified before the Commission in support of the Company's Fiscal Year ("FY") 2025 Electric Infrastructure, Safety and Reliability Plan in Docket No. 23-48-EL, the Company's Petition for Acceleration Due to DG Project – Tiverton Projects in Docket No. 23-37-EL and the Company's Petition for Acceleration Due to DG Project – Weaver Hill Projects in Docket No. 23-38-EL.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's FY 2025 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 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, 2024, to March 31, 2025. As described in Mr. Jeffrey Oliveira's pre-filed direct testimony, the plant in service investment and the O&M expenses are used to calculate the FY 2025 Electric ISR Plan revenue requirement. As explained in Mr. Tyler Shields' pre-filed direct testimony, 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 2025 to develop the CapEx and O&M Reconciliation Factors. Specific details by category for the FY 2025 Electric ISR Plan plant additions, associated cost of removal ("COR"), and actual capital spending are included in Attachment EJW-1.

III. Plant In Service

Q. Please provide an overview of the plant in service for FY 2025.

A. As shown in Table 2 of Attachment EJW-1, in FY 2025, the Company placed $115.1 million of plant additions in service. This amount was $15.0 million more than the forecast of $100.1 million in the approved FY 2025 Electric ISR Plan. This $15.0 million difference is a result of: (i) receiving and placing into service an additional $9.5 million of transformers, (ii) $5.0 million of additional spending for the Nasonville damage/failure project, and (iii) $4.0 million for the Tiverton distribution line project. The Company is still reviewing the transformer category to find the root cause of the transformer overspend. However, the overspend currently is attributed to transformers ordered by the Company while it was still under National Grid USA ownership that had fluctuating and inaccurate lead times. These transformers were delivered in FY 2025, which were not expected and could not be forecasted at the time the budget was prepared. The increased plant in service associated with the Nasonville damage/failure project is due to higher-than-forecasted material costs and unforeseen design changes resulting from the compressed timeframe of the project. The Tiverton distribution line plant in service amount is due to the Company accelerating the project and placing it into service during FY 2025, instead of over the next five years, to increase efficiencies, reduce team costs, and avoid cost increases due to inflation. The Company includes details on FY 2025 Plant in Service in Section I of Attachment EJW-1.

As shown in Table 3 of Attachment EJW-1, Cost of Removal was $22.7 million, which was $3.3 million higher than the FY 2025 budget of $19.3 million. The Company includes details on FY 2025 Cost of Removal in Section I of Attachment EJW-1.

The combined plant in service and cost of removal totaled $137.8 million, which was $18.4 million over the Company's forecast. Additional details on these variances are included in Section I of Attachment EJW-1.

IV. Capital Spending

Q. Please summarize the Company's actual capital spending, excluding Advanced Metering Functionality projects, for FY 2025 for the Electric ISR Plan.

A. As shown in Table 4 of Attachment EJW-1, capital spending, excluding Advanced Metering Functionality projects, totaled $140.9 million, which was $9.4 million more than the budget of $131.6 million. Capital spending drivers are discussed in Section III of Attachment EJW-1.

Q. Please provide an update on AMF spending.

A. The Company spent $48.6 million on AMF capital during FY 2025. The Company filed its 2024 Annual AMF Progress Report on December 23, 2024. The Report provides an update on the Program's progress. No assets were placed in service during FY 2025 and there is no rate impact associated with AMF investment to date.

Q. Is there an adjustment to the FY 2025 revenue requirement for overspending the Consolidated Soft Budget Cap by more than 2.5 percent?

A. Yes.

Q. How did the Company reflect this adjustment for overspending its Soft Budget Cap?

A. Please see Mr. Oliveira's pre-filed direct testimony.

Q. Why is the FY 2025 total capital spend (excluding AMF) identified in the reconciliation filing less than what is identified in the FY 2025 ISR Fourth Quarter report?

A. The adjusted total of $140.9 million is $1.0 million lower than the total that was reported in the Company's FY 2025 Fourth Quarter ("Q4") report. This change is mainly the result of removing pre-construction costs incurred in FY 2025 for projects that will be constructed in future fiscal years and are now being advanced separate from the Company's ISR spending.

Q. Why did the Company choose to remove projects and programs that were approved through the FY 2025 ISR?

A. Although the Public Utilities Commission ("PUC") concurred with progressing $131.6 million of projects and programs within the FY 2025 ISR capital plan, the Company had to make subsequent adjustments to meet the newly approved FY 2026 ISR budget. While modifying the capital plan to meet the budgetary constraints, the Company had to balance immediate system needs with affordability concerns. While the Company was able to meet the FY 2026 ISR Capital Plan budget, there were several projects and programs that were already approved during the FY 2025 ISR Docket that were still needed to satisfy immediate system needs but did not fit within the FY 2026 ISR budget. Therefore, the Company decided to progress these projects and programs outside the ISR plan and remove all pre-construction costs associated with these projects from the FY 2025 ISR plan.

Q. Does the Company anticipate seeking cost recovery for these projects?

A. Yes, the Company anticipates including them as part of rate base in its next base distribution rate case after each project has been placed into service.

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 began during FY 2025 and is expected to be completed by the Fall of 2025.

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 explain the spending associated with Transformers.

A. During FY 2025, the Company spent $17.5 million on the purchase of transformers, capacitors, and voltage regulators. The additional spending on transformers resulted from the same reasons as described above regarding plant additions and, for those reasons, the Company does not anticipate similar situations to occur on future purchases because lead times have stabilized.

Q. Please provide an update on the United States Department of Energy's ("DOE") Infrastructure Investment and Jobs Act ("IIJA") Grid Resilience and Innovation Partnerships ("GRIP") Funding Opportunity, Smart Grid Topic Area.

A. The Company has continued to work closely with the DOE to execute on the Smart Grid funding and evaluate modifications to the award to align with the current work plan.

Q. Are any FY 2025 investments eligible for IIJA reimbursement?

A. Yes, certain work related to the Tiverton Distribution Line project, NWRI Common Items project, and one work order under the Reliability Blanket are eligible for IIJA reimbursement, and the Company is in the process of submitting a reimbursement request.

Q. Has the Company reduced the ISR spending and plant additions by the estimated reimbursement?

A. No, the value is unknown at this time and will be reviewed and potentially modified by the DOE.

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

A. 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.

V. O&M Spending

Q. Please summarize the Company's actual O&M spending for the FY 2025 Electric ISR Plan.

A. Total O&M spending was $13.9 million as compared to a budget of $14.1 million. As shown in Table 12 of Attachment EJW-1, for FY 2025, the Company's vegetation management O&M spending was $13.3 million, which was over-budget by $0.2 million. In addition, as shown in Table 13, 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 $0.7 million, $0.4 million under budget. Detailed information regarding the work completed is discussed in Attachment EJW-1 in Section IV and Section V, respectively.

VI. Reliability Performance

Q. Please summarize the results of the Company's reliability performance for CY 2024.

A. Section VI of Attachment EJW-1 includes the Company's Reliability Performance for calendar year 2024 (CY 2024). The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2024, with SAIFI of 0.83 against a target of 1.05, and SAIDI of 60.98 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[1]

VII. <u>Review of Distributed Generation ("DG") Projects</u>

Q. Are there any Distributed Generation ("DG") projects included in the FY 2025 ISR Reconciliation for rate recovery?

A. No. Capital spending is included in the DG category; however, no plant additions associated with DG projects are included in this reconciliation filing. The Company did not have any reconciled projects during this fiscal year where there were (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. Does this conclude your testimony?

A. Yes.

[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.

Attachment EJW-1

FY 2025 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing

Fiscal Year 2025 Electric Infrastructure, Safety, and Reliability Plan Annual Reconciliation Filing

EXECUTIVE SUMMARY

In accordance with its tariff, RIPUC No. 2255, 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, 2024, through March 31, 2025 ("ISR Plan Fiscal Year 2025" or "FY 2025") for the Electric Infrastructure, Safety, and Reliability Plan approved by the Rhode Island Public Utilities Commission ("PUC") in Docket No. 23-48-EL. This filing provides the actual capital spending and operation and maintenance ("O&M") spending for the Electric ISR Plan Fiscal Year 2025. In addition, actual Plant in Service and Cost of Removal spending are compared to targets by spending category. Finally, this filing includes a summary of the Company's reliability performance for the calendar year ("CY") ending December 31, 2024. Table 1 summarizes the FY 2025 Plan.

Table 1
FY 2025 ISR Plan Activity

	(a)	(b)	(c)	(d)
	in millions $	**Target / Budget**	**Actuals**	**Variance Over / (Under)**
1	**Plant Additions - Soft Budget Cap projects**	$100.1	$115.2	$15.0
2	Separately Tracked Major Projects	0.0	(0.0)	(0.0)
3	Fiber Study Costs	0.0	0.0	0.0
4	**Plant Additions excluding AMF**	**100.1**	**115.1**	**15.0**
5	Advanced Metering Functionality	0.0	0.0	0.0
6	**Plant in Service**	**$100.1**	**$115.1**	**$15.0**
7	**Cost of Removal - Soft Budget Cap projects**	$15.3	$19.5	$4.2
8	Separately Tracked Major Projects	4.0	3.2	(0.8)
9	Fiber Study Costs	0.0	0.0	0.0
10	**Cost of Removal excluding AMF**	**19.3**	**22.7**	**3.3**
11	Advanced Metering Functionality	0.0	0.0	0.0
12	**Total Cost of Removal**	**$19.3**	**$22.7**	**$3.3**
13	**Capital Spending - Soft Budget Cap**	**$118.6**	**$127.5**	**$8.8**
14	Separately Tracked Major Projects	12.7	13.4	0.6
15	Fiber Study Costs	0.2	0.1	(0.1)
16	**Capital Spending excluding AMF**	**131.6**	**140.9**	**9.4**
17	Advanced Metering Functionality	48.2	48.6	0.4
18	**Total Capital Spending**	**$179.8**	**$189.5**	**$9.8**
19	Vegetation Management Spending	$13.1	$13.3	$0.2
20	I&M and Other O&M Spending	1.1	0.7	(0.4)
21	**O&M Spending**	**$14.1**	**$13.9**	**($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 adjustment that was made for the tax hold harmless impact on ISR rate base[1] as well as other tax updates. As shown in Mr. Oliveira's testimony, for the ISR Plan Fiscal Year 2025 filing, the Company has an updated revenue requirement of $59.1 million.

Mr. Shields' testimony provides a description of the reconciliation of the final actual FY 2025 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 0.42, or approximately 0.3% from $138.80 to $139.22.

I. Fiscal Year 2025 Electric ISR Plan Plant Additions and Cost of Removal

As shown in Table 2 below, plant additions of $115.1 million were placed in service, $15.0 million over the target amount of $100.1 million. The major drivers for higher actual plant additions are:

- increased transformer purchases which are placed into service when purchased.
- higher additions associated with the completion of the Nasonville Substation Damage/Failure project and the Tiverton Distribution Line project.
- lower additions associated with Providence Study Phase 1B and Phase 4 projects.

The Company did not place any assets related to Distribution Generation projects in service during FY 2025.

[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)	(b) Target	(c) Actuals	(d) Variance Over / (Under)
1	Customer Request/Public Requirement	$29,746,823	$36,828,769	$7,081,946
2	Damage Failure	20,285,417	26,458,222	6,172,805
3	Asset Condition	38,401,006	39,533,653	1,132,646
4	Non-Infrastructure	830,236	554,747	(275,490)
5	System Capacity & Performance	10,874,248	11,779,559	905,311
6	**Plant Additions - Subtotal**	**$100,137,731**	**$115,154,950**	**$15,017,219**
7	Separately Tracked Major Projects	0	(36,109)	(36,109)
8	Fiber Study Costs	0	0	0
9	**Plant Additions excluding AMF**	**100,137,731**	**115,118,841**	**14,981,110**
10	Advanced Metering Functionality	0	0	0
11	**Total Plant Additions**	**$100,137,731**	**$115,118,841**	**$14,981,110**

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 FY 2025, which was $22.7 million, $3.3 million over the budget of $19.3 million. Increased spending on environmental investigation and contamination remediation at the Pawtucket #1 Substation, part of the Southeast Substation project, was the primary reason for the overspend. Other differences between budgeted and actual removal costs were related to the increased number of New Business and Damage/Failure Blanket projects and removal costs associated with joint owned poles. These were offset by lower removal costs on Asset Condition area study projects.

Table 3
Cost of Removal by Category

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	Customer Request/Public Requirement	$2,363,000	$4,314,981	$1,951,981
2	Damage Failure	2,079,000	2,588,996	509,996
3	Asset Condition	9,509,633	10,199,499	689,866
4	Non-Infrastructure	20,000	0	(20,000)
5	System Capacity & Performance	1,344,907	2,396,284	1,051,377
6	**Cost of Removal - Subtotal**	15,316,540	19,499,760	4,183,220
7	Separately Tracked Major Projects	4,003,040	3,157,638	(845,402)
8	Fiber Study Costs	0	0	0
9	**Cost of Removal excluding AMF**	**19,319,580**	**22,657,398**	**3,337,818**
10	Advanced Metering Functionality	0	0	0
11	**Total Cost of Removal**	**$19,319,580**	**$22,657,398**	**$3,337,818**

II. ISR Plan Fiscal Year 2025 Capital Spending Summary

As shown in Table 4 below, capital spending, excluding Advanced Metering Functionality projects, totaled $140.9 million, which was $9.4 million over the budget of $131.6 million. Spending in each of the categories is discussed in more detail below.

Table 4
Capital Spending by Category

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	**Capital Spending**			
2	Customer Request/Public Requirement	$32,862,000	$44,668,084	$11,806,084
3	Damage Failure	17,813,000	25,270,604	7,457,604
4	Asset Condition	44,546,678	35,294,629	(9,252,049)
5	Non-Infrastructure	892,000	550,551	(341,449)
6	System Capacity & Performance	22,506,000	21,674,571	(831,429)
7	**Consolidated Soft Budget Cap**	**118,619,678**	**127,458,439**	**8,838,761**
8	Separately Tracked Major Projects	12,749,250	13,383,754	634,504
9	Fiber Study Costs	200,000	100,488	(99,512)
10	**Capital Spending excluding AMF**	**131,568,928**	**140,942,681**	**9,373,753**
11	Advanced Metering Functionality	48,191,799	48,597,581	405,782
12	**Total Capital Spending**	**$179,760,727**	**$189,540,262**	**$9,779,536**

III. ISR Plan Fiscal Year 2025 Capital Spending by Key Driver Category

a. Customer Request/Public Requirement

Capital spending for FY 2025 in the Customer Request/Public Requirement category was $44.7 million, which was $11.8 million over the budget of $32.9 million. The major drivers of this variance are:

- Capital spending associated with the purchase of transformers, voltage regulators, and capacitors was $17.5 million, $9.5 million over budget. The Company is still reviewing the transformer category to find the root cause of the transformer overspend. However, the overspend currently is attributed to transformers ordered by the Company while it was still under National Grid USA ownership that had fluctuating and inaccurate lead times. These transformers were delivered in FY 2025, which were not expected and could not be forecasted at the time the budget was prepared. The budget was based on previous years' spending. The Company forecasts that spending on transformers will decrease in future years.

- Capital spending on New Business work was $27.0 million, $10.2 million over budget. Capital spending on emerging commercial and residential customer requests, for both blanket-level projects and specific projects, exceeded the amounts budgeted and the reserves established. At the time the Company developed the FY 2025 budgets, specific projects in this category were not known. The Company thus proposed budgets and reserves based on historical costs, adjusting for any known trends or one-time items.

- For FY 2025, the Public Requirements category was under budget by $4.6 million. Spending on Rhode Island Department of Transportation and other public requirements work was lower than expected and offset by increased billing for joint owned pole replacements.

- Distributed Generation ("DG") capital spending activity, net of DG customer contributions, was $2.6 million under budget for the year, as the Company offsets capital spending with customer contributions and corrects a prior year entry where material costs were incorrectly duplicated. The Company did not place any assets related to Distribution Generation projects in service during FY 2025

- Capital spending for Third Party Attachments, Land and Land Rights, AMR Meter Purchases and Installations/Changes, and Outdoor Lighting totaled $3.2 million and were under budget by $0.7 million. See Attachment E for additional information.

The budget and actual spending by budget classification for the Customer Request/Public Requirement category are shown in Table 5 below.

Table 5
Customer Request/Public Requirement Capital Spending

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	Third-party Attachments	$288,000	$90,545	($197,455)
2	Distributed Generation	1,000,000	(1,646,717)	(2,646,717)
3	Land and Land Rights	515,000	172,273	(342,727)
4	Meters & Related Work	2,533,000	2,591,027	58,027
5	New Business – Commercial	9,366,000	18,303,882	8,937,882
6	New Business – Residential	7,428,000	8,723,321	1,295,321
7	Outdoor Lighting	592,000	390,586	(201,414)
8	Public & Regulatory Requirement	3,140,000	(1,502,614)	(4,642,614)
9	Transformers & Related Equipment	8,000,000	17,543,411	9,543,411
10	Strategic DER Investments	0	2,370	2,370
11	**Total Customer Request / Public Requirement Spending**	**$32,862,000**	**$44,668,084**	**$11,806,084**

b. Damage/Failure

Capital spending in the Damage/Failure category was $25.3 million, which was $7.5 million over the budget of $17.8 million. This variance was driven by the following:

- Overhead Line and Substation Damage/Failure Blanket project capital spending was $16.2 million. The Company completed its review of FY 2025 work and reclassified $1.4 million to the Asset Replacement Blanket project. Certain monthly confirming work during August 2024 to March 2025 was charged to the Damage/Failure blanket project. The Company will continue to review Damage/Failure work during FY 2026 to ensure proper categorization.

- Capital spending related to the Nasonville Substation Damage/Failure project was $3.6 million, $2.0 million over budget due to higher costs than originally estimated. Assets were placed into service as of March 31, 2025. Spending on close out activities during FY 2026 is forecasted to be minimal.

- Capital spending for Vault 72 Reconstruction and Westerly, Hopkins Hill, and Apponaug Spare Transformers totaled $1.1 million.

- Actual capital spending related to storms and weather-related events was $4.3 million, $1.3 million over budget.

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

Table 6
Damage/Failure Capital Spending

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	Damage/Failure Blanket Projects	$11,268,000	$16,232,152	4,964,152
2	Nasonville Substation Failure	1,637,000	3,599,623	1,962,623
3	Other Failed Assets	900,000	1,091,064	191,064
4	Reserves for Failed Assets	1,008,000	0	(1,008,000)
5	Storms and Weather Events	3,000,000	4,347,764	1,347,764
6	**Total Damage / Failure Spending**	**$17,813,000**	**$25,270,604**	**$7,457,604**

c. <u>Asset Condition</u>

Capital spending in the Asset Condition category excluding Separately Tracked Large Projects was $35.3 million, which was $9.3 million under the budget of $44.5 million. The following projects and programs were included in this category of spending:

- Capital spending on the Providence Area Study Projects was $10.7 million, $9.6 million under budget for the year. This underspend was due to a shift in the delivery of cable for the Admiral Street Cable project (Phase 1B) from FY 2025 to FY 2026 and due to completion of the Knightsville line work in FY 2024 instead of FY 2025.

- During FY 2025, capital spending on inspection and maintenance work (“I&M”) was $4.1 million, $2.5 million over budget due to construction on sub-transmission lines that had been deferred in previous years. Please see the Company’s response to data request DIV 7-3 in Docket 24-54 EL for more information on the additional work completed in FY 2025.

- Capital spending related to the Asset Replacement Blanket Projects was $6.3 million, which was over budget by $0.2 million for the year. The Company completed its review of FY 2025 work and reclassified $1.4 million to the Asset Replacement Blanket project from the Damage/Failure Blanket project. Certain monthly confirming work during August 2024 to March 2025 should have been charged to the Asset Replacement Blanket project instead of the Damage/Failure blanket project. The Company continues to review the work in the Asset Replacement blanket projects to ensure proper categorization.

- Capital spending for the Underground Cable Replacement Program was $6.1 million -- $0.6 million over budget. Due to the availability of resources, the Company completed several projects and put the assets into service.

- Capital spending for the URD Cable Replacement Program was $4.3 million -- $0.7 million under budget. Spending was reduced for the URD program to offset overspend in other areas, including the Underground Cable Replacement Program.

- FY 2025 budgets were not established for Pawtucket Substation's control house construction and wiring (part of the Southeast Substation project) and for the Dyer Street Substation distribution line project. Capital spending on these projects totaled $1.2 million during the fiscal year.

- Work began or continued on several of the 25 Asset Condition Area Study Projects, but spending on many projects was delayed or deferred resulting in capital spending of $1.8 million against a budget of $4.3 million. These delays were due to resource constraints and additional analysis requirements.

For additional commentary, please see Attachment E – Asset Condition – Other Area Study Projects Detail.

The budget and actual spending for the Asset Condition category are shown in Table 7 below.

Table 7
Asset Condition Capital Spending

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	Underground Cable Replacement	$5,500,000	$6,140,909	$640,909
2	URD Cable Replacement	4,999,678	4,307,235	(692,443)
3	Blanket Projects	6,177,000	6,349,367	172,367
5	I&M Program	1,530,000	4,060,352	2,530,352
6	Substation Spare Transformers	540,000	0	(540,000)
7	Other Area Study Projects	4,327,000	1,693,117	(2,633,883)
8	Providence Area Study Projects	20,382,000	10,732,581	(9,649,419)
9	Dyer Street Substation D Line Project	0	555,688	555,688
10	Southeast Substation D Line Project	0	672,055	672,055
11	Batteries / Chargers	195,000	239,756	44,756
12	UG Improvements	700,000	254,042	(445,958)
13	Other Projects	196,000	289,526	93,526
14	**Total Asset Condition Spending**	**$44,546,678**	**$35,294,629**	**($9,252,049)**

d. Non-Infrastructure

Spending on Non-Infrastructure projects was $0.6 million, $0.3 million under the budget of $0.9 million. The deferral of the Copper to Fiber Conversion project was the main driver of the underspend. The Company is considering the project's integration with other projects.

Detailed budget and actual spending are shown in Table 8 below.

Table 8
Non-Infrastructure Capital Spending

	(a)	(b) Budget	(c) Actuals	(d) Variance Over / (Under)
1	Corporate Overheads	$0	($4,312)	($4,312)
2	General Equipment	412,000	554,663	142,663
3	Telecommunications	300,000	11	(299,989)
4	Copper to Fiber Conversions	180,000	189	(179,811)
5	**Non-Infrastructure Spending**	**$892,000**	**$550,551**	**($341,449)**

e. **System Capacity & Performance**

Capital spending for FY 2025 for the System Capacity and Performance category was $21.7 million, which was $0.8 million under the FY 2025 budget of $22.5 million. This variance was driven primarily by the following projects:

- During FY 2025, capital spending for the East Providence Substation distribution line project was $3.6 million. Although delays in obtaining an easement and crew resource availability presented delays during the year, the Company completed its FY 2025 work plan.
- During FY 2025, capital spending on the Warren Substation and distribution line projects was $1.6 million, which was $0.2 million under budget. For FY 2026 ISR budgetary and reporting purposes, the Warren Substation (D-Sub) project (C065166) has been identified as a Separately Tracked Major Project.
- During FY 2025, capital spending on the New Lafayette Substation and distribution line projects was over budget by $0.1 million. For FY 2026 ISR budgetary and reporting purposes, the New Lafayette Substation (D-Sub) project (C081675) has been identified as a Separately Tracked Major Project.
- The Tiverton Distribution Line project, originating from the Tiverton Area Study, has been completed. Spending for the year totaled $3.8 million. The project's budget was $0.3 million for FY 2025 and $2.4 million for FY 2026 through FY 2029. The assets were placed into service during the year. The Company chose to complete the project during FY 2025, instead of over multiple years, to increase efficiencies, reduce team costs and avoid cost

increases associated with inflation. Additional information related to the Tiverton D-Line project is provided in the Company's response to data request PUC 15-3 in Docket No. 23-48-EL, the Commission's Fifteenth Set of Data Requests – Quarter 1 Report.

- Capital spending for the Weaver Hill Road Substation and distribution line projects was $0.3 million in FY 2025, under budget by $0.8 million. Archaeological studies of the Weaver Hill Road Substation site identified numerous archeological artifacts limiting potential locations for the substation on the site. The Company is assessing the feasibility of site locations and has a backup site plan. No major equipment was ordered during FY 2025. For additional information on delays associated with the project, please see the Company's response to DIV 5-2 in Docket 24-54 EL.

- Capital spending for the System Capacity & Performance Blanket Projects was $2.7 million, essentially on budget. Work identified during annual capacity and reliability reviews is included in the blanket projects to reduce outage exposure, as well as typical small dollar work that benefits reliability.

- In FY 2025, capital spending on System Capacity & Performance area study projects, excluding the Tiverton distribution line project, was $2.7 million, which was $3.0 million under budget. These delays were due to labor resource constraints.

- Capital spending for the remaining programs and projects totaled $5.9 million, which was $0.6 million over budget. Please see Attachment E for more information on program and project variances.

Budgeted 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)
Line		Budget	Actuals	Variance Over / (Under)
1	Aquidneck Island Projects	$0	$192,003	$192,003
2	New Lafayette Substation	910,000	1,033,288	123,288
3	Warren Substation	1,800,000	1,584,663	(215,337)
4	East Providence D Line Project	3,600,000	3,637,626	37,626
5	Tiverton Substation D Line Project	328,000	3,820,330	3,492,330
6	Weaver Hill Road Substation	1,105,000	336,268	(768,732)
7	3V0	186,000	314,299	128,299
8	EMS / RTU	135,000	9,641	(125,359)
9	Overloaded Transformer Replmt	1,500,000	1,516,380	16,380
10	Blanket Projects	2,605,000	2,675,434	70,434
11	Other Area Study Projects	5,717,000	2,701,265	(3,015,735)
12	CEMI-4	1,230,000	1,394,157	164,157
13	Electromech Relay Upgrades	1,234,000	1,195,746	(38,254)
14	VVO-Smart Caps and Regs	400,000	4,080	(395,920)
15	Mobile Substation	1,278,000	0	(1,278,000)
16	Other Programs and Projects	478,000	1,259,390	781,390
17	**System Capacity & Performance Spending**	**$22,506,000**	**$21,674,571**	**($831,429)**

f. Separately Tracked Major Projects

Capital spending in FY 2025 for the Separately Tracked Major Projects category was $13.4 million. The Commission summarized the capital spending framework for Separately Tracked Major Projects in its Order issued on October 25, 2024. The Order requires separate tracking of major projects equal to or greater than $5 million in overall spending with a project-based budget cap based on a construction phase estimate. The Company provides updates related to these projects in Attachment G of its quarterly reporting.

Table 10 below lists the Separately Tracked Major Projects in FY 2025 and capital spending:

Table 10
Separately Tracked Major Projects Capital Spending

	(a)	(b)	(c)	(d)
Line		**Budget**	**Actuals**	**Variance Over / (Under)**
1	Asset Condition:			
2	Dyer St Substation	$15,000	($38,833)	($53,833)
3	Southeast Substation	$0	$3,736	3,736
4	Admiral St 12kV Substation	5,513,000	5,359,927	(153,073)
5	Kingston Substation Equipment Rplmt	400,000	55,475	(344,525)
6	Phillipsdale Substation	100,000	0	(100,000)
7	Apponaug Substation	150,000	208,239	58,239
8	Hospital Substation Equipment Rplmt	320,000	41,266	(278,734)
9	System Capacity & Performance:			
10	East Providence Substation	2,685,000	2,077,969	(607,032)
11	Nasonville Substation	3,566,250	5,675,975	2,109,725
12	**Separately Tracked Major Projects**	**$12,749,250**	**$13,383,754**	**$634,504**

g. Fiber Study Costs

The Fiber Study was received December 2024. Capital spending for FY 2025 totaled $100,000 against a budget of $200,000.

h. Advanced Metering Functionality (AMF)

In the FY 2025 ISR Plan, the Company included capital spending associated with the deployment of its AMF program, described in Docket No. 22-49-EL, as a separate category. The Company filed its 2024 Annual AMF Progress Report on December 23, 2024. The report covers the period from the inception of the AMF Program through November 30, 2024. The Report provides an update on the Program's progress. The project is on schedule having met all deliverables and key milestones, with the exception of the timing of Release 2A which will not impact the deployment schedule.

Capital spending of $48.6 million took place during FY 2025. Actual spending was slightly higher than the budget primarily due to the front loading of 41,647 meters from FY 2026 to FY 2025. This increase in meter spending was offset by lower spending in the systems and program categories driven by the timing of internal IT support, Release 2A milestone payment achievement, as well as the timing of program vendor onboarding and support. Table 11 below shows the budgeted and actual capital spending by category. No assets were placed in service during the year and there is no rate impact associated with AMF in-service to date.

Table 11
AMF

	(a)	(b)	(c)	(d)
		Budget	**Actuals**	**Variance Over / (Under)**
1	Meter Costs	$28,725,476	$34,992,287	$6,266,811
2	Network Costs	4,478,693	4,171,744	(306,949)
3	System Costs	11,486,710	7,347,207	(4,139,503)
4	Program Costs	3,500,920	2,086,343	(1,414,577)
5	**Capital Spending - AMF**	**$48,191,799**	**$48,597,581**	**$405,782**

IV. Vegetation Management

In FY 2025, the Company completed 1,149 miles of distribution cycle pruning, at a cost of $13.3 million. Table 12 below provides the spending components.

Table 12
Vegetation Management O&M Spending

Line	(a)	(b) Budget	(c) Actuals	(d) Variance Over / (Under)
1	Cycle Pruning (Base)	$8,400,000	$8,515,304	$115,304
2	Cycle Trimming Treatment (TGR)	125,000	50,874	(74,126)
3	Risk Reduction - on cycle	750,000	915,281	165,281
4	Hazard Tree	400,000	349,036	(50,964)
5	Sub-Transmission	700,000	691,747	(8,253)
6	Police / Flaggers	900,000	928,692	28,692
7	Pockets of Poor Performance	50,000	20,250	(29,750)
8	Core Crew (all other activities)	1,750,000	1,790,186	40,186
9	**Total VM O&M Spending**	**$13,075,000**	**$13,261,370**	**$186,370**

For additional information about the Vegetation Management program, please see the Company's FY 2025 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2025 (Docket No. 23-48-EL) filed with the PUC on May 15, 2025. A copy of this report is attached as Attachment 1.

V. Other O&M

For FY 2025, the Company completed 100% of its annual overhead structure inspection goal with an associated spending of $0.5 million. Table 13 below provides the spending components in the Other O&M category.

Table 13
Other O&M Spending

Line	(a)	(b) Budget	(c) Actuals	(d) Variance Over / (Under)
1	Opex Related to Capex	$200,000	$114,647	($85,353)
2	Repair & Inspections Related Costs	500,000	546,867	46,867
3	System Planning & Protection Coordination St	0	0	0
4	VVO/CVR Program	365,000	0	(365,000)
5	**Total I&M and Other O&M Spending**	**$1,065,000**	**$661,514**	**($403,486)**

For additional information about the I&M program, please see the Company's FY 2025 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2025 (Docket No. 23-48-EL) filed with the PUC on May 15, 2025. A copy of this report is attached as Attachment 1.

VI. Reliability Performance

In CY 2024, the Company exceeded its System Average Interruption Frequency Index ("SAIFI") performance metrics with SAIFI of 0.83 against a target of 1.05 and earning an offset of $27,989. The Company met its System Average Interruption Duration Index ("SAIDI") performance metrics with a SAIDI of 60.98 minutes, against a target of 71.9 minutes. For additional information on reliability and major event days, please refer to the 2024 Service Quality Report filed under Docket No. 3628 on May 1, 2025. A copy is included in this report as Attachment 2.

VII. FY 2026 Five Year Investment Plan with Details and FY 2025 Actuals

In Docket No. 24-54-EL, the Company provided a five-year budget with a forecast for FY 2025 spending as Attachment 3, Bates pages 140-146. This presentation has been updated to include FY 2025 actual spending and a revised five year investment plan reflecting the Commission's Written Order issued on July 17, 2025. The five year budget plan with actual FY 2024 spending is shown below.

FY 2026 Five-Year Investment Plan with Details and FY 2025 Actuals

$'000s

Line Number	(a) Spending Rationale and Category	(b) ISR Grouping	(c) FY 2025 Budget	(d) FY 2025 Actuals	(e) FY 2026	(f) FY 2027	(g) FY 2028	(h) FY 2029	(i) FY 2030	(j) Major Project - Current Phase	(k) Total Project Forecast *	(l) Construction Grade Estimate +/-10%	Initial Estimate	(m) Date of Estimate	(n) Est'd Constr Start	(o) Est'd Constr End	(p) Cap Spending through FY 2024
					5 Year Investment Plan - Capital Spending					Major Project - Details							
1	**Customer Request/Public Requirement**																
2		New Business - Commercial	$9,366	$18,304	11,854	10,786	11,317	11,400	11,800								
3		New Business - Residential	7,428	8,723	7,500	7,715	7,930	8,146	8,463								
4		Public Requirements	3,140	(1,503)	1,669	1,725	1,882	1,939	2,100								
5		Transformers and Related Equipment	8,000	17,543	8,000	8,000	8,000	8,000	8,000								
6		Meters and Meter Work	2,533	2,591	430	100	100	100	100								
7		Distributed Generation	1,000	(1,647)	1,000	1,000	1,000	1,000	1,000								
8		Third Party Attachments	288	91	300	300	300	300	300								
9		Land and Land Rights	515	172	450	450	450	450	450								
10		Outdoor Lighting	592	391	300	300	300	300	300								
11		Other	-	2	-	-	-	-	-								
12	**Total Customer Request/Public Requirement**		**32,862**	**44,668**	**31,503**	**30,375**	**31,279**	**31,635**	**32,513**								
13	**Damage Failure**																
14		Damage /Failure	11,268	16,232	12,020	12,340	12,760	13,085	13,510								
15		Nasonville Substation Failure	1,637	3,600	104		-	-	-								
16		Failed Assets - Specific Projects	900	1,091	3,593	1,474	-	-	-								
17		Reserves	1,008	-	-	-	-	-	-								
18		Storms	3,000	4,348	4,500	5,200	5,300	5,500	5,600								
19	**Total Damage Failure**		**17,813**	**25,271**	**20,217**	**19,014**	**18,060**	**18,585**	**19,110**								

FY 2026 Five-Year Investment Plan with Details and FY 2025 Actuals

$'000s

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)	(n)	(o)	(p)
					5 Year Investment Plan - Capital Spending					Major Project - Details							
Line Number	Spending Rationale and Category	ISR Grouping	FY 2025 Budget	FY 2025 Actuals	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Major Project - Current Phase	Total Project Forecast *	Construction Grade Estimate +/-10%	Initial Estimate	Date of Estimate	Est'd Constr Start	Est'd Constr End	Cap Spending through FY 2024
1	**Asset Condition**																
2		Providence Study Ph1A-Ph4	20,382	10,733	12,796	10,395	2,464	-	-								
3		Auburn Conversion & Line	492	-	-	-	-	-	-								
4		Phillipsdale Substation D Line	100	-	-	-	-	-	-								
5		Underground Cable Replacement	5,500	6,141	4,250	4,250	4,250	6,500	6,500								
6		URD Cable Replacement	5,000	4,307	-	-	4,100	5,500	5,500								
7		Blanket projects	6,177	6,349	6,340	6,500	6,361	6,850	6,900								
8		I&M	1,530	4,060	2,037	1,530	1,530	1,530	1,530								
9		Substation Spare Transformers	540	-	-	-	-	-	-								
10		Substation Breakers & Reclosers			-	440	-	-	-								
11		Other Area Study Projects - BSVS	781	935	536	795	1,677	1,809	2,083								
12		Other Area Study Projects - CRIE	50	25	-	258	819	287	-								
13		Other Area Study Projects - CRIW	1,883	309	1,372	3,699	3,942	2,692	2,745								
14		Other Area Study Projects - East Bay	-	-	-	-	-	-	-								
15		Other Area Study Projects - Newport	446	91	987	1,262	466	-	-								
16		Other Area Study Projects - NWRI	500	327	-	1,236	3,266	1,331	202								
17		Other Area Study Projects - Providence	-	-	-	-	-	-	735								
18		Other Area Study Projects - SCW	-	-	-	-	1,307	2,917	2,536								
19		Other Area Study Projects - Tiverton	75	6	396	800	1,348	-	-								
20		ACNW Vault Vent Blower Replmt	700	254	675	695	716	-	-								
21		Batteries / Chargers	195	240	307	154	276	683	232								
22		Reserve	-	-	-	-	-	6,599	10,092								
23		Other Projects and Programs	196	1,517	-	-	-	-	-								
24	**Total Asset Condition**		**44,547**	**35,295**	**29,696**	**32,014**	**32,521**	**36,698**	**39,054**								
25	**Non-Infrastructure**		-	-													
26		General Equip & Telecom Blanket	712	550	400	410	420	440	450								
27		Verizon Copper to Fiber	180	0	-	-	-	-	-								
28	**Total Non-Infrastructure**		**892**	**551**	**400**	**410**	**420**	**440**	**450**								

FY 2026 Five-Year Investment Plan with Details and FY 2025 Actuals

$'000s

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)	(n)	(o)	(p)
					5 Year Investment Plan - Capital Spending					Major Project - Details							
Line Number	Spending Rationale and Category	ISR Grouping	FY 2025 Budget	FY 2025 Actuals	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Major Project - Current Phase	Total Project Forecast *	Construction Grade Estimate +/-10%	Initial Estimate	Date of Estimate	Est'd Constr Start	Est'd Constr End	Cap Spending through FY 2024
1	**System Capacity & Performance**																
2		East Providence Substation D Line	3,600	3,638	3,062	2,731											
3		Warren Substation	1,050	840	-	-	-	-	-								
4		Warren Substation D Line	750	745	3,219	4,139	-	-	-								
5		New Lafayette Substation	160	976	-	-	-	-	-								
6		New Lafayette Substation D Line	750	58	2,700	514	-	-	-								
7		Weaver Hill Road Substation	1,105	336	2,074	3,966	2,987	1,592	-								
8		Tiverton Substation D Line	328	3,820													
9		Blanket Projects	2,605	2,675	3,616	3,904	5,692	5,860	6,040								
10		Mobile Substation	1,278	-	-	-	-	-	-								
11		CEMI-4 Program	1,230	1,394	1,230	-	-	-	-								
12		Electromechanical Relay Upgrades	1,234	1,196	528	1,300	5,700	5,300	4,100								
13		VVO-Smart Capacitors and Regulators	400	-	-	-	-	-	-								
14		3V0 Program	186	314													
15		EMS/RTU Program	135	10	262	891	1,803	773	-								
16		Transformer Upgrades	1,500	1,516	1,500	1,500	1,500	1,500	1,500								
17		Other Area Study Projects - BSVS	680	-	-	-	-	-	-								
18		Other Area Study Projects - CRIW	1,441	1,438	1,000	2,647											
19		Other Area Study Projects - East Bay	84	56	-	248	1,639	-	-								
20		Other Area Study Projects - Newport	793	85	1,356	479	-	-	-								
21		Other Area Study Projects - NWRI	108	698	1,423	230	-	-	-								
22		Other Area Study Projects - SCE	1,684	78	1,177	3,415	4,486	-	-								
23		Other Area Study Projects - SCW	927	347	532	206	5,202	5,653	5,220								
24		Reserve	-	-	-	-	-	6,600	10,091								
25		Other projects and programs	478	1,455	100	100	100	100	100								
26	**Total System Capacity & Performance**		**22,506**	**21,675**	**23,779**	**26,270**	**29,107**	**27,378**	**27,051**								
27	**Consolidated Soft Budget Limit**		**118,620**	**127,458**	**105,595**	**108,083**	**111,387**	**114,736**	**118,178**								

FY 2026 Five-Year Investment Plan with Details and FY 2025 Actuals

$'000s

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		(m)	(n)	(o)	(p)
					5 Year Investment Plan - Capital Spending					Major Project - Details							
Line Number	**Spending Rationale and Category**	**ISR Grouping**	**FY 2025 Budget**	**FY 2025 Actuals**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Major Project - Current Phase**	**Total Project Forecast ***	**Construction Grade Estimate +/-10%**	**Initial Estimate**	**Date of Estimate**	**Est'd Constr Start**	**Est'd Constr End**	**Cap Spending through FY 2024**
1	**Separately Tracked Major Projects**																
2	**Asset Condition**	Admiral Street 12kV Substation	5,513	5,360	6,998	495	-	-	-	Detailed Eng'g	$15,922	--	$12,831	Aug-21	Sep-21	FY 2027	$3,069
3		Dyer Street Substation	15	(39)	-	-	-	-	-	Construction	$15,451	n/a	$10,658	Apr-21	Sep-21	FY 2025	$15,490
4		Apponaug Substation	150	208	-	773	3,892	4,526	-	Prelim Eng'g	$9,426	--	$5,700	Jul-23	May-26	FY 2029	$27
5		Southeast Substation	-	4	-	-	-	-	-	Construction	$14,097	n/a	$10,684	Jun-19	Oct-19	FY 2025	$14,093
6		Phillipsdale Substation	100	-	-	-	-	-	-	Prelim Eng'g	$18,891	--	$19,332	May-24	Jun-26	FY 2030	$0
7		Centredale Substation	-	-	-	773	5,026	1,025	-	Prelim Eng'g	$6,961	--	$6,963	Nov-24	May-26	FY 2029	$137
8		Auburn 115/12.4kV Substation	-	-	-	-	-	-	-	--	$10,337	--		--	--	--	--
9		Hospital Substation Equipment Replacement	320	41	-	515	2,936	5,804	-	Prelim Eng'g	$9,395		$5,360	Dec-21		FY 2030	$100
10		Kingston Substation Equipment Replacement	400	55	-	618	4,172	3,000	10,000	Prelim Eng'g	$17,943	--	$16,805	Dec-21	Oct-25	FY 2029	$98
11		Merton Substation Equipment Replacement	-	-	-	200	2,314	3,500	3,500	--	$9,514	--	--	--	--	--	--
12	**Syst Cap & Perf**	East Providence Substation	2,685	2,078	4,836	7,848	-	-	-	Detailed Eng'g	$16,357	--	$6,000	Feb-17	Aug-25	FY 2028	$1,595
13		Nasonville Substation	3,566	5,676	6,420	2,241	-	-	-	Detailed Eng'g	$15,895	$14,800	$10,786	Jul-23	Jan-25	FY 2026	$2,558
14		Chase Hill Substation	-	-	-	3,844	1,333	1,373	-		$6,550	--	--	--	--	--	--
15		New Lafayette Substation	-	-	3,785	-	-	-	-	Detailed Eng'g	$7,802	--	$5,232	Oct-20	Jan-25	FY 2026	$4,017
16		Warren Substation	-	-	3,281	2,508	-	-	-	Detailed Eng'g	$6,891	--	$3,500	Feb-17	Jun-25	FY 2026	$1,102
17	**Total Separately Tracked Major Projects**		**12,749**	**13,384**	**25,320**	**19,815**	**19,673**	**19,228**	**13,500**								
18	**Study Costs - Fiber Network Study**		**200**	**100**	**-**	**-**	**-**	**-**	**-**								
19	**Advanced Metering Functionality ("AMF")**		**48,192**	**48,598**	**88,047**	**15,544**	**-**	**-**	**-**								
20	**Total Capital Spending including AMF**		**$179,761**	**$189,540**	**218,962**	**143,442**	**131,060**	**133,964**	**131,678**								
21	**Total Capital Spending excluding AMF ****		**$131,569**	**$140,943**	**130,915**	**127,898**	**131,060**	**133,964**	**131,678**								

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 Electric ISR Reconciliation filings certain information about work performed on CEMI-4 feeders selected for inclusion in the ISR Plan. This information is under review and will be reported as soon as it is available.

Attachment 1

Quarterly Report for the Fourth Quarter Period Ending March 31, 2025

Andrew S. Marcaccio, Counsel
PPL Services Corporation
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280 Melrose Street
Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

May 15, 2025

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. 23-48-EL – FY2025 Electric Infrastructure, Safety, and Reliability Plan Quarterly Update – Fourth Quarter Ending March 31, 2025

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy, attached, please find the Company's Fiscal Year ("FY") 2025 Electric Infrastructure, Safety, and Reliability ("ISR") Plan quarterly update for the period ending March 31, 2025. 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 23-48-EL Service List

Electric Infrastructure, Safety, and Reliability Plan
ISR Plan Fiscal Year 2025 – Fourth Quarter Update
For the Twelve Months Ending March 31, 2025

EXECUTIVE SUMMARY

As shown in Attachment A, The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") spent $142.0 million for capital projects against a budget of $131.6 million during Fiscal Year 2025 (April 1, 2024 through March 31, 2025, or "FY 2025") for its Electric Infrastructure, Safety, and Reliability ("ISR") Plan. Actual spending under the Consolidated Soft Budget Cap, which includes capital spending for projects not identified as Major Projects or Study Costs, was $127.7 million against a budget of $118.6 million for FY 2025. The overspend mainly was attributable to higher than budgeted new business customer requests, failures, and transformer purchases. Capital spending on Separately Tracked Major Projects was $14.2 million, $1.4 million under budget. The Fiber Study was completed in December 2024. Capital spending for the year totaled $100,000 against a budget of $200,000.

Advanced Metering Functionality ("AMF") capital spending is not included in the amounts above. For FY 2025, AMF capital spending was $48.6 million.

I. FY 2025 Capital Spending by Key Driver Category

1. Base Spending

a. <u>Customer Request/Public Requirement</u>

During FY 2025, capital spending in the Customer Request/Public Requirement category was $44.7 million, which was $11.8 million over budget. Major variances include:

- Distributed Generation ("DG") capital spending activity, net of DG customer contributions, was under budget by $1.6 million for the year, as the Company offsets capital spending with customer reimbursements and contributions and corrects a prior year entry.

- Capital spending on New Business work was $27.0 million. Capital spending on emerging commercial and residential customer requests, for both blanket-level projects and specific projects, exceeded the amounts budgeted and the reserves established. At the time the Company developed the FY 2025 budgets, specific projects in this category were not known. The Company thus proposed budgets and reserves based on historical costs, adjusting for any known trends or one-time items.

- Capital spending associated with the purchase of transformers, voltage regulators, and capacitors was $17.5 million. Purchases of transformers and related equipment are over budget because both availability and unit pricing of transformers were in flux due to supply chain issues. The budget was based on previous years' spending. The Company forecasts that spending on transformers will decrease in future years.

- For FY 2025, the Public Requirements category was under budget by $1.5 million. Spending on Rhode Island Department of Transportation and other public requirements work was lower than expected and offset by increased billing for joint owned pole replacements.

- Capital spending for Third Party Attachments, Land and Land Rights, AMR Meter Purchases and Installations/Changes, and Outdoor Lighting totaled $3.3 million and was under budget by $0.7 million. See Attachment E for additional information.

b. Damage/Failure

During FY 2025, capital spending in the Damage/Failure category was $26.7 million, which was $8.9 million over budget. The major drivers are:

- Spending in the Overhead Line and Substation Damage/Failure Blanket projects was $17.6 million. Please see Attachment F for more detailed information on spending in the Damage/Failure blankets. The Company continues to review Damage/Failure blankets to ensure proper categorization.

- Actual capital spending related to storms and weather-related events was $4.3 million --$1.3 million over budget.

- Capital spending related to the Nasonville Substation Damage/Failure project was $3.6 million, $2.0 million over budget due to higher costs than originally estimated. Assets were placed into service as of March 31, 2025. FY 2026 spending on closeout activities is forecasted to be minimal.

- Capital spending for Vault 72 Reconstruction and Westerly, Hopkins Hill, and Apponaug Spare Transformers totaled $1.1 million. See Attachment E for additional information.

c. Asset Condition

During FY 2025, capital spending in the Asset Condition category was $34.0 million -- $10.5 million under budget. The major drivers in this category are as follows:

- Capital spending on the Providence Area Study Projects was $10.7 million, $9.6 million under budget for the year. This underspend was primarily due to Phase 1B cable delivery being pushed to FY2025 and Phase 4 – Knightsville projects coming in under budget due to accelerated completion of the line work in FY2024.
- During FY 2025, capital spending on inspection and maintenance work ("I&M") was $4.1 million, $2.5 million over budget due to construction on sub-transmission lines that had been deferred in previous years. Please see the Company's response to data request DIV 7-3 in Docket 24-54 EL for more information on the additional work completed in FY 2025 for the I&M Program.

- Capital spending related to the Asset Replacement Blanket Projects was $4.9 million, which was under budget by $1.2 million for the year. The Company continues to review the Asset Replacement blanket projects to ensure proper categorization.

- Capital spending for the Underground Cable Replacement Program was $6.1 million -- $0.6 million over budget. Although forecasted in the last quarterly report to come in under budget due to limited resources, resources were available, and the Company was able to complete several projects and put the assets into service.

- Capital spending for the URD Cable Replacement Program was $4.3 million -- $0.7 million under budget. Spending was reduced for the URD program to offset overspend in other areas, including the Underground Cable Replacement Program.

- FY 2025 budgets were not established for capital spending related to Pawtucket Substation's control house construction and wiring (part of the Southeast Substation project) and additional spending on the Dyer Street Substation distribution line. Capital spending on these projects totaled $1.2 million during the fiscal year.
- Work began or continued on several of the 25 Asset Condition Area Study Projects, but spending on many projects was delayed or deferred resulting in capital spending of $1.8 million against a budget of $4.3 million. The substation transformers were not ordered. For additional commentary, please see Attachment E – Asset Condition – Other Area Study Projects Detail.
- The Company deferred the initial payments on the three spare transformers budgeted in FY 2025. The budget was $540,000.

d. ***Non-Infrastructure***

The Non-Infrastructure spending category ended the year under budget. The Copper to Fiber Conversion project has been deferred as the Company considers its integration with other projects.

e. ***System Capacity and Performance***

During FY 2025, capital spending for the System Capacity and Performance category was $21.8 million, $0.7 million under budget. The major drivers in this category are as follows:

- During FY 2025, capital spending for the East Providence Substation distribution line project was $3.6 million. Although delays in obtaining an easement and crew resource availability presented delays during the year, the Company completed its FY 2025 work plan.

- During FY 2025, capital spending on the Warren Substation and distribution line projects was $1.6 million, which was $0.2 million under budget. For FY 2026 ISR budgetary and reporting purposes, the Warren Substation (D-Sub) project (C065166) has been identified as a Separately Tracked Major Project.

- During FY 2025, capital spending on the New Lafayette Substation and distribution line projects was over budget by $0.1 million. For FY 2026 ISR budgetary and reporting purposes, the New Lafayette Substation (D-Sub) project (C081675) has been identified as a Separately Tracked Major Project.

- The Tiverton Distribution Line project, originating from the Tiverton Area Study, has been completed. Spending for the year totaled $3.8 million. The project's budget was $0.3 million for FY 2025 and $2.4 million for FY 2026 through FY 2029. The assets were placed into service during the year. The Company chose to complete the project during FY 2025, instead of over multiple years, to increase efficiencies, reduce team costs, and avoid cost increases associated with inflation. Additional information related to the Tiverton D-Line project is provided in the Company's response to data request PUC 15-3 in Docket No. 23-48-EL, the Commission's Fifteenth Set of Data Requests – Quarter 1 Report.

- Capital spending for the Weaver Hill Road Substation and distribution line projects was $0.3 million in FY 2025, under budget by $0.8 million. Archaeological studies of the Weaver Hill Road Substation site have been completed. The surveys identified numerous archeological artifacts limiting potential locations for the substation on the site. Please see the Company's response to DIV 5-2 in Docket 24-54 EL for more information on the delays associated with the project.

- Capital spending for the System Capacity & Performance Blanket Projects was $2.7 million, essentially on budget. Work identified during annual capacity and reliability reviews is included in the blanket projects to reduce outage exposure, as well as typical small dollar work that benefits reliability.

- In FY 2025, capital spending on System Capacity & Performance area study projects, excluding the Tiverton distribution line project, was $2.8 million, which was $2.9 million under budget. Please see Attachment E – System Capacity & Performance – Other Area Study Projects Detail for additional detail.

- The Company deferred the initial payments for the mobile substations in FY 2025. The budget was $1.3 million.

- Capital spending for the remaining programs and projects totaled $5.9 million, which was $0.7 million over budget. Please see Attachment E for more information on the variances.

f. Advanced Metering Functionality (AMF)

In the FY 2025 ISR Plan, the Company included capital spending associated with the deployment of its AMF program, described in Docket No. 22-49-EL, as a separate category outside of Base Spending. The Company filed its 2024 Annual AMF Progress Report on December 23, 2024. The report covers the period from the inception of the AMF Program through November 30, 2024. The Report provides an update on the Program's progress. The project is on schedule having met all deliverables and key milestones, with the exception of the timing of Release 2A, which will not impact the deployment schedule.

Capital spending of $48.6 million took place during FY 2025. Spending was slightly higher than budget primarily due to the front loading of 41,647 meters from FY 2026 to FY 2025. This increase in meter spending was offset primarily by lower spending in the systems and program categories driven by the timing of internal IT support, Release 2A milestone payment achievement, as well as the timing of program vendor onboarding and support. The table below shows the budgeted and actual capital spending by category:

	(a)	(b)	(c)	(d)
	Fiscal Year Ending March 31, 2025 *$000's*			
Line Number		**Budget**	**Actual**	**Over / (Under)**
1	Meter Costs	$28,725	$34,992	$6,267
2	Network Costs	4,479	4,172	(307)
3	System Costs	11,487	7,347	(4,140)
4	Program Costs	3,501	2,086	(1,415)
5	**Total AMF Capital Spending**	**$48,192**	**$48,598**	**$406**

g. ***Separately Tracked Major Projects***

As part of the FY 2025 ISR Plan approval, the Company separately reports on multi-year substation projects with capital spending estimated to be greater than $5.0 million. In addition to separate reporting, the capital spending associated with these projects is excluded from the Consolidated Soft Budget Cap. The following substation projects are reported on separately: Admiral Street, Dyer Street, Apponaug, Phillipsdale, East Providence Substation, Nasonville, Hospital, and Kingston. Each project is discussed in Attachment G. The current stage for each project is noted on the project's summary page. A table listing the major project lifecycle stages and describing the milestones is included on the last page of Attachment G.

h. ***Updated Five Year Investment Plan***

The Company provides an updated Five-Year Investment Plan that includes explanations for variances exceeding +/- 10% of the FY 2025 budget in quarterly reports. This project information is provided in Attachment E. The Five Year Investment Plan, columns (e) through (i), has been updated to include the FY 2026 ISR budget approved at the Public Utility Commission's March 28, 2025 Open Meeting.

i. ***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 distributed energy resources (DER) 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. The Company also is exploring new techniques and methodologies to evaluate resiliency, wildfire mitigation, and FERC 2222 concepts.

j. ***Procurement Update***

The Company continues to monitor the impact of inflation and supply chain disruptions, including fuel, construction, regulatory and environmental compliance costs, and other costs, including impacts as a result of tariffs that could affect pricing or delivery of equipment sourced from outside the United States. The Company will provide updates as they become available.

3. Investment Placed-in-Service

During FY 2025, $115.1 million of plant additions were placed into service, against a $100.1 million Plant in Service target for FY 2025. The major drivers for higher actual plant additions than budgeted plant additions are:

- increased transformer purchases which are placed into service when purchased
- higher additions associated with the completion of the Nasonville Substation Failure and the Tiverton Distribution Line projects
- Lower additions associated with Providence Study Phase 1B and Phase 4 projects

The Plant Additions table is shown in Attachment B.

4. Vegetation Management

During FY 2025, the Company completed 1,149 miles of distribution cycle pruning against the fiscal year goal of 1,145 miles. The Company spent $13.3 million, against a $13.1 million budget. An additional three miles of cycle pruning was completed due to the reconfiguration of feeders. Additional spending was incurred related to On-Cycle Risk Reduction to obtain extra clearance for certain spans.

Attachment C provides the O&M spending and the agreed upon tree and span counts, as well as the feeders worked.

5. Inspection and Maintenance

I&M program costs for the fiscal year are shown in Attachment D. During this time, the Company identified one Level I deficiency on July 1, 2024. An energized service was identified. A repair was made the same day. When Level I deficiencies are identified, they are made safe immediately and repaired within 30 days of the inspection.

The Company began its annual inspection of targeted overhead structures and elevated voltage testing on January 1, 2025, because inspections and elevated voltage testing take place on a calendar year basis. The table below shows the number of units tested during this period.

Line Number	(a)	(b)	(c)	(d)	(e)
	Manual Elevated Voltage Testing				
1	**Manual Elevated Voltage Testing**	**Total System Units Requiring Testing**	**Units Completed 1/1/25 thru 3/31/25**	**Units with Voltage Found (>1.0v)**	**Percent of Units Tested with Voltage (>1.0v)**
2	Distribution Facilities	274,396	10,664	0	0.000%
3	Underground Facilities	12,438	0	0	0.000%
4	Street Lights and Signal Controls	4,929	0	0	0.000%

Attachment A

Capital Spending
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)
		Fiscal Year Ending March 31, 2025		
Line Number		Budget	Actual	Over / (Under)
1	**Base Capital Spending**			
2	Customer Requests / Public Requirements	$32,862	$44,675	$11,813
3	Damage / Failure	17,813	26,681	8,868
4	Asset Condition	44,547	34,026	(10,520)
5	Non-Infrastructure	892	551	(341)
6	System Capacity & Performance	22,506	21,775	(731)
7	**Consolidated Soft Budget Cap**	**118,620**	**127,707**	**9,087**
8	Separately Tracked Major Projects	12,749	14,176	1,426
9	Fiber Study Costs	200	100	(100)
10	**Total Capital Spending excluding AMF**	**131,569**	**141,983**	**10,414**
11	Advanced Metering Functionality (AMF)	48,192	48,598	406
12	**Total Capital Spending including AMF**	**$179,761**	**$190,581**	**$10,820**

Attachment B

Plant Additions
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)
		Fiscal Year Ending March 31, 2025		
Line Number		**Target**	**Actual**	**Over / (Under)**
1	Customer Request/Public Requirement	$29,747	$36,772	$7,025
2	Damage Failure	20,285	27,868	7,583
3	***Non-Discretionary Subtotal***	***50,032***	***64,640***	***14,608***
4	Asset Condition	38,401	38,127	(274)
5	Non- Infrastructure	830	555	(275)
6	System Capacity & Performance	10,874	11,773	899
7	***Discretionary (excluding AMF) Subtotal***	***50,105***	***50,455***	***350***
8	Advanced Metering Functionality (AMF)	*0*	*0*	*0*
9	***Discretionary Subtotal***	***50,105***	***50,455***	***350***
10	**Total Plant Additions**	**$100,138**	**$115,096**	**$14,958**

Attachment C

Vegetation Management
For the Twelve Months Ending March 31, 2025
($000)

Table 1 - Vegetation Management O&M Spending

	(a)	(b)	(c)	(d)
		Fiscal Year Ending March 31, 2025		
Line Number		Budget	Actual	Over / (Under)
1	Cycle Pruning (Base)	$8,400	$8,515	$115
2	Cycle Trimming Treatment (TGR)	125	51	(74)
3	Risk Reduction - on cycle	750	879	129
4	Hazard Tree	400	349	(51)
5	Sub-Transmission	700	692	(8)
6	Police / Flaggers	900	902	2
7	Pockets of Poor Performance	50	20	(30)
8	Core Crew (all other activities)	1,750	1,737	(13)
9	Expenditures not categorized yet	0	116	116
10	**Total**	**$13,075**	**$13,261**	**$186**

Attachment C

Vegetation Management
For the Twelve Months Ending March 31, 2025

Table 2 - Span and Tree Tracker

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	FY 2025 Trees by Feeder through 3/31/25						
		On-cycle Risk Reduction		On Cycle Extra Clearance			
Line Number	Feeder	Spans Worked	Trees Removed	Spans Worked	Trees Removed	**SPANS TOTAL**	**TREES TOTAL**
1	100F1	11	4				
2	102W54			15	10		
3	127W41	20	5	20	28		
4	155F8	98	100	49	18		
5	15F2			22	27		
6	22F6	3	6				
7	23F2	116	314	23	43		
8	23F4	3	1				
9	23F5	72	267				
10	27F2	1	1				
11	30F2	92	81	22	8		
12	33F4	1	1				
13	34F2	3	5	25	77		
14	38F5			1			
15	45F2	14	6	7	8		
16	48F3	1	1				
17	54F1		4	45	29		
18	57J2	26	6				
19	61F1			8	10		
20	61F2	10	8	5	6		
21	61F3	1	1	18	9		
22	63F2			12	16		
23	64F1	25	5	26	3		
24	64F2	7	5	16	6		
25	68F2	133	181				
26	85T3	5	6				
27	**TOTAL**	**642**	**1,007**	**313**	**297**	**955**	**1,303**

Attachment C

Vegetation Management
For the Twelve Months Ending March 31, 2025

Table 3 - Span and Tree Tracker

	(a)	(b)	(c)	(d)
	FY 2025 EHTM/HTO by Feeder through 3/31/25			
Line Number	Feeder	Trees Removed	Substation	District
1	112W42	45	Staples	Capital
2	112W44	14	Staples	Capital
3	126W51	3	Washington	Capital
4	14F2	5	Drumrock	Capital
5	155F2	11	Chase Hill	Coastal
6	155F4	19	Chase Hill	Coastal
7	155F6	3	Chase Hill	Coastal
8	15F1	1	Hope	Capital
9	15F2	3	Hope	Capital
10	18F14	3	Johnston	Capital
11	23F1	3	Farnum Pike	Capital
12	26W3	6	Woonsocket	Capital
13	26W5	4	Woonsocket	Capital
14	27F1	1	Pomtiac	Capital
15	30F1	1	Lafayette	Coastal
16	34F1	1	Chopmist	Capital
17	52F2	1	Warwick	Coastal
18	59F3	1	Peacedale	Coastal
19	68F1	5	Kenyon	Coastal
20	68F4	1	Kenyon	Coastal
21	88F1	13	Tower Hill	Coastal
22	88F3	5	Tower Hill	Coastal
23	2227	12	Johnston	Capital
24	**TOTAL**	**161**		

Attachment C

Vegetation Management
For the Twelve Months Ending March 31, 2025

Table 4 - Span and Tree Tracker

	(a)	(b)	(c)	(d)	(e)
	FY 2025 Off Cycle Ash Tree Removal Count through 3/31/25				
Line Number	Feeder	Trees Removed	Substation	District	Work Type
1	127W41	4	Nasonville	Capital	On-cycle Risk
2	112W42	45	Staples	Capital	HAZ
3	112W44	14	Staples	Capital	HAZ
4	26W3	6	Woonsocket	Capital	HAZ
5	26W5	4	Woonsocket	Capital	HAZ
6	2227	12	Johnston	Capital	HAZ
7	155F8	25	Chase Hill	Coastal	On-cycle Risk
8	18F14	2	Johnston	Capital	HAZ
9	**TOTAL**	**112**			

Attachment D

Inspection and Maintenance Program and Other O&M Spending
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)
		Fiscal Year Ending March 31, 2025		
Line Number		**Budget**	**Actual**	**Over / (Under)**
1	Opex Related to Capex	$200	$115	($85)
2	Inspections & Repair Related Costs	500	547	47
3	System Planning & Protection Coordination Study	0	0	0
4	VVO/CVR Program	365	0	(365)
5	**Total Other O&M Spending**	**$1,065**	**$662**	**($403)**

Attachment E
Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		FY 2026 ISR 5 Year Investment Plan					
Line Number	Spending Rationale	Category	Budget	Actual	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Explanation of FY 2025 variances more than 10%
1	**Customer Request / Public Requirement**									
2		New Business - Commercial	$9,366	$18,304	$11,854	$10,786	$11,317	$11,400	$11,800	Emerging work exceeded the amounts budgeted and the reserves established.
3		New Business - Residential	7,428	8,724	7,500	7,715	7,930	8,146	8,463	Emerging work exceeded the amounts budgeted and the reserves established.
4		Public Requirements	3,140	(1,501)	1,669	1,725	1,882	1,939	2,100	Fewer DOT projects than in previous years, offset by increased JO pole billing.
5		Transformers and Related Equipment	8,000	17,543	8,000	8,000	8,000	8,000	8,000	Availability and pricing were in flux due to supply chain issues, delivery of delayed units from previous years.
6		Meters and Meter Work	2,533	2,598	430	100	100	100	100	--
7		Distributed Generation	1,000	(1,647)	1,000	1,000	1,000	1,000	1,000	Application of CIACs and reversal of entry from prior years.
8		Third Party Attachments	288	91	300	300	300	300	300	Spending on projects that had customer advances received in prior year.
9		Land and Land Rights	515	172	450	450	450	450	450	Actual costs came in under the amount budgeted.
10		Outdoor Lighting	592	391	300	300	300	300	300	Actual costs came in under the amount budgeted.
11	**Total Customer Request/Public Requirement**		**32,862**	**44,675**	**31,503**	**30,375**	**31,279**	**31,635**	**32,513**	
12	**Damage / Failure**									
13		Damage /Failure	11,268	17,642	12,020	12,340	12,760	13,085	13,510	Increase in monthly confirming work.
14		Reserves	1,008	-	-	-	-	-	-	Reserves reduced to $0.
15		Failed Assets	2,537	4,691	1,503	1,474	-	-	-	Nasonville Sub Rebuild increased construction and material costs, shifting costs from FY26 to FY25.
16		Storms	3,000	4,348	4,500	5,200	5,300	5,500	5,600	Actual storm costs came in over the amount budgeted.
17	**Total Damage/Failure**		**17,813**	**26,681**	**18,023**	**19,014**	**18,060**	**18,585**	**19,110**	

Attachment E
Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		**FY 2026 ISR 5 Year Investment Plan**					
Line Number	**Spending Rationale**	**Category**	**Budget**	**Actual**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Explanation of FY 2025 variances more than 10%**
1	**Asset Condition**									
2		Underground Cable Replacement	5,500	6,141	4,250	4,500	4,500	6,500	6,500	Resource availability allowed for completion of several projects and put the assets into service.
3		URD Cable Replacement	5,000	4,307	4,100	4,500	4,500	5,500	5,500	Spending reduced to offset overspend in other areas.
4		Blanket Projects	6,177	4,939	6,340	6,500	6,681	6,850	6,900	Actual costs came in the under amount budgeted.
5		I&M	1,530	4,060	1,530	1,530	1,530	1,530	1,530	Construction on lines that had been deferred in previous years.
6		Substation Spare Transformers	540	4	3,860	8,526	7,816	6,225	6,300	Initial deposits deferred to FY26.
7		Substation Breakers & Reclosers	196	(143)	440	-	-	-	-	Reclass removal costs from CAPEX.
8		Phillipsdale & Centredale Sub D Line *	-	-	1,950	5,171	1,353	196	-	FY 25 budget and spending are shown in Other AS Projects-East Bay and in Other AS Projects - NWRI, respectively.
9		Gate II Equipment Repl. *	-	-	-	512	419	-	-	FY25 budget shown in Other Area Study Projects - Newport.
10		Auburn Conversion & Line *	-	-	1,100	5,192	11,632	9,042	-	FY25 budget shown in Other Area Study Projects - Providence.
11		Other Area Study Projects - BSVS	781	935	928	1,570	2,219	2,022	1,156	See Asset Condition - Other Area Study Projects Detail table below.
12		Other Area Study Projects - CRIE	50	25	250	795	279	-	-	--
13		Other Area Study Projects - CRIW	1,883	369	6,106	9,559	3,668	478	-	See Asset Condition - Other Area Study Projects Detail table below.
14		Other Area Study Projects - East Bay	100	78	-	-	-	-	-	--
15		Other Area Study Projects - Newport	446	91	470	1,569	-	-	-	See Asset Condition - Other Area Study Projects Detail table below.
16		Other Area Study Projects - NWRI	500	327						See Asset Condition - Other Area Study Projects Detail table below.
17		Other Area Study Projects - Providence	492	-	-	-	-	-	735	See Asset Condition - Other Area Study Projects Detail table below.
18		Other Area Study Projects - SCW	-	-	-	-	1,307	2,917	2,536	See Asset Condition - Other Area Study Projects Detail table below.
19		Tiverton Substation	75	6	396	2,148	-	-	-	--
20		Providence Area Study Projects	20,382	10,733	12,796	10,395	2,464	-	-	Shifting of spending between fiscal years.
21		Dyer Street Substation - D Line	-	556	-	-	-	-	-	Completion of underground cable replacement deferred from FY24.
22		Southeast Substation - D Line	-	672	-	-	-	-	-	Add'l work required to Pawtucket Sub bldg before decommissioning.
23		Reserve	-	-	-	-	1,270	1,270	13,000	--
24		Batteries / Chargers	195	240	307	154	276	683	232	--
25		UG Improvements and Other	700	686	675	695	716	-	-	--
26	**Total Asset Condition**		**44,547**	**34,026**	**45,498**	**63,317**	**50,630**	**43,213**	**44,389**	
27	**Non-Infrastucture**									
28		General Equip & Telecom Blanket	712	555	400	410	420	440	450	Actual costs came in under the amount budgeted.
29		Capital Overheads	-	(4)	-	-	-	-	-	--
30		Verizon Copper to Fiber	180	0	-	-	-	-	-	Deferred as integration with other projects is considered.
31	**Total Non-Infrastructure**		**892**	**551**	**400**	**410**	**420**	**440**	**450**	

* Reclassified to from Other Area Study Projects in FY 2025 to a separate line item in the FY 2026 ISR 5 Year Investment Plan.

Attachment E
Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		**FY 2026 ISR 5 Year Investment Plan**					
Line Number	**Spending Rationale**	**Category**	**Budget**	**Actual**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Explanation of FY 2025 variances more than 10%**
1	**System Capacity & Performance**									
2		Aquidneck Island	-	192	-	-	-	-	-	Harrison and Kingston Sub Imprvmts and D Line projects.
3		New Lafayette Substation**	910	1,033	2,700	514	-	-	-	Early delivery of material offsetting delays in construction.
4		Warren Substation **	1,800	1,585	3,219	4,139	-	-	-	Delays.
5		East Providence Substation D Line	3,600	3,638	3,062	2,731	-	-	-	--
6		Weaver Hill Road Substation	1,105	336	2,074	3,966	2,987	1,592	-	See Sec I(1)(e) - delay due to archeological artifacts located on site.
7		3V0	186	314	-	-	-	-	-	In correct charges will be reclassed in FY26.
8		EMS/RTU	135	10	591	2,974	750	-	-	Deferred work.
9		Overloaded Transformer Replcmts	1,500	1,516	1,500	1,500	1,500	1,500	1,500	--
10		Blanket Projects	2,605	2,675	3,616	5,524	5,692	5,860	6,040	--
11		Other Area Study Projects - BSVS	680	100	1,599	2,168	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
12		Other Area Study Projects - CRIW	1,441	1,438	1,000	2,647	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
13		Other Area Study Projects - East Bay	84	56	241	1,591	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
14		Other Area Study Projects - Newport	793	85	851	945	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
15		Other Area Study Projects - NWRI	108	698	1,423	230	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
16		Other Area Study Projects - SCE	1,684	78	3,127	5,788	-	-	-	See System Cap & Perf - Other Area Study Projects Detail table below.
17		Other Area Study Projects - SCW	927	347	732	5,050	5,488	5,068	-	See System Cap & Perf - Other Area Study Projects Detail table below.
18		Tiverton Substation D Line	328	3,820	-	-	-	-	-	Accelerated.
19		Reserve	-	-	-	-	1,270	1,270	17,500	--
20		CEMI-4	1,230	1,394	1,230	1,230	1,230	2,349	2,420	Closeout costs on FY25 projects.
21		ADMS/DERMS Advanced	-	-	-	4,012	1,991	-	-	--
22		DER Monitor/Manage	-	-	-	2,906	5,135	-	-	--
23		Electromech Relay Upgrades	1,234	1,196	652	2,393	6,215	4,396	3,225	--
24		VVO - Smart Cap's and Reg's	400	4	1,250	4,250	6,700	6,700	9,600	Delays in engineering.
25		Mobile Substation	1,278	-	3,830	7,670	-	-	-	Spending deferred.
26		Other projects and programs	478	1,259	100	100	100	100	100	Deferral from FY24 due to easement issues, reviewing forecast.
27	**Total System Capacity & Performance**		**22,506**	**21,775**	**32,797**	**62,328**	**39,058**	**28,836**	**40,385**	

** For FY 2026 ISR budgetary and reporting purposes, the Warren Substation project (#C065166) and the New Lafayette Substation project (#C081675) have been identified as a Separately Tracked Major Project. During FY 2025 these substation projects were included in the Consolidated Soft Budget Limit.

Attachment E
Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		**FY 2026 ISR 5 Year Investment Plan**					
Line Number	**Spending Rationale**	**Category**	**Budget**	**Actual**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Explanation of FY 2025 variances more than 10%**
1	**Adjustment to Allowed FY 2026 Budget**		**-**	**-**	**(22,626)**	**-**	**-**	**-**	**-**	
2	**Consolidated Soft Budget Cap**		**118,620**	**127,707**	**105,595**	**175,444**	**139,446**	**122,709**	**136,847**	
3	**Separately Tracked Major Projects**									
4	*Asset Condition*	Dyer Street Substation	15	(35)	-	-	-	-	-	See Attachment G.
5		Admiral St 12 KV Substation	5,513	5,360	6,998	495	-	-	-	See Attachment G.
6		Kingston Substation Equipment Repl	400	55	-	-	-	-	-	See Attachment G.
7		Centredale Substation	-	-	-	-	-	-	-	See Attachment G.
8		Phillipsdale Substation	100	792	-	5,500	5,500	4,500	1,391	See Attachment G.
9		Apponaug Substation	150	208	-	-	-	-	-	See Attachment G.
10		Hospital Substation Equipment Repl	320	41	-	-	-	-	-	See Attachment G.
11		Merton Substation Equipment Repl	-	-	-	-	-	-	-	See Attachment G.
12		Auburn 115/12.4kV Substation	-	-	-	1,057	2,112	6,336	832	See Attachment G.
13	*System Capacity &*	East Providence Substation	2,685	2,078	4,836	7,848	-	-	-	See Attachment G.
14	*Performance*	Chase Hill Substation - Second Half	-	-	-	-	-	-	-	See Attachment G.
15		Nasonville Substation	3,566	5,676	6,420	2,241	-	-	-	See Attachment G.
16		New Lafayette Substation **	-	-	3,785	-	-	-	-	See Attachment G.
17		Warren Substation **	-	-	3,281	2,508	-	-	-	See Attachment G.
18	**Total Separately Tracked Major Projects**		**12,749**	**14,176**	**25,320**	**19,649**	**7,612**	**10,836**	**2,223**	
19	**Study Costs - Fiber Network Study**		**200**	**100**	**-**	**-**	**-**	**-**	**-**	
20	**Advanced Metering Functionality (AMF)**									
21		Meter Costs	28,725	34,992	61,778	4,212	-	-	-	Front loading of meters.
22		Network Costs	4,479	4,172	8,343	1,985	-	-	-	--
23		System Costs	11,487	7,347	14,316	7,597	-	-	-	Timing of internal IT support and Release 2A finalization.
24		Program Costs	3,501	2,086	3,610	1,751	-	-	-	Timing of program vendor onboarding and support.
25	**Total AMF**		**48,192**	**48,598**	**88,047**	**15,544**	**-**	**-**	**-**	
26	**Total Capital Spending including AMF**		**$179,761**	**$190,581**	**$218,962**	**$210,637**	**$147,058**	**$133,545**	**$139,070**	
27	**Total Capital Spending excluding AMF**		**$131,569**	**$141,983**	**$130,915**	**$195,093**	**$147,058**	**$133,545**	**$139,070**	

28	**Consolidated Soft Budget Cap**	**$118,620**	**$127,707**	**$105,595**	**$175,444**	**$139,446**	**$122,709**	**$136,847**
29	**Separately Tracked Major Projects**	**12,749**	**14,176**	**25,320**	**19,649**	**7,612**	**10,836**	**2,223**
30	**Fiber Study Costs**	**200**	**100**	**-**	**-**	**-**	**-**	**-**
31	**Total Capital Spending (excluding AMF)**	**131,569**	**141,983**	**130,915**	**195,093**	**147,058**	**133,545**	**139,070**
32	**Advanced Metering Functionality (AMF)**	**48,192**	**48,598**	**88,047**	**15,544**	**-**	**-**	**-**
33	**ISR Capital Spending**	**$179,761**	**$190,581**	**$218,962**	**$210,637**	**$147,058**	**$133,545**	**$139,070**

** For FY 2026 ISR budgetary and reporting purposes, the Warren Substation project (#C065166) and the New Lafayette Substation project (#C081675) have been identified as a Separately Tracked Major Project. During FY 2025 these substation projects were included in the Consolidated Soft Budget Limit.

Attachment E
Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		**FY 2026 ISR 5 Year Investment Plan**					
Line Number	**Spending Rationale**	**Category**	**Budget**	**Actual**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Explanation of FY 2025 variances more than 10%**
1	**O&M Spend**									
2		Vegetation Management	$13,075	$13,261						
3		I&M - Opex Related to Capex	200	115						
4		I&M - Inspections & Replairs Related Costs	500	547						
5		System Planning & Protection Coordination Stu	-	-						
6		VVO/CRV	365	-						
7	**Total O&M**		**$14,140**	**$13,923**						

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		FY 2026 ISR 5 Year Investment Plan					
Line Number	Area Study	Project	Budget	Actual	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	Explanation of FY 2025 variances more than 10%
1	**Asset Condition - Other Area Study Projects Detail**									
2		Centre St Substation (D-Sub)	-	-	-	32	65	65	54	--
3		Centre St Substation (D-Line)	-	-	-	200	400	400	332	--
4		Pawtucket Substation (D-Sub)	-	-	-	92	183	183	153	--
5		Pawtucket Substation (D-Line)	-	-	-	371	741	741	617	--
6		Valley and Farnum 23kV Conversion	200	151	-	-	-	-	-	--
7		Central Falls Sub (D-Line)	231	192	392	484	367	633	-	--
8		Crossman St Sub (D-Line)	350	592	536	391	463	-	-	Accelerated construction in FY25 from FY26.
9	BSVS - Other Area Study Projects - Total		781	935	928	1,570	2,219	2,022	1,156	
10		Apponaug Substation (D-Line)	50	25	250	795	279	-	-	--
11	CRIE - Other Area Study Projects - Total		50	25	250	795	279	-	-	
12		Division St T1 T2 Replacement	500	59	1,468	2,960	-	-	-	Transformer down payment deferred.
13		Coventry Sub Relocation	200	9	1,028	1,601	445	-	-	Transformer down payment deferred.
14		Anthony Sub Equipment Replacement	350	9	1,489	1,090	727	-	-	Transformer down payment deferred.
15		Warwick Mall Sub Equipment Replacement	150	33	830	1,402	416	-	-	Transformer down payment deferred.
16		Hope Sub Equipment Replacement	209	25	294	1,155	1,113	-	-	Transformer down payment deferred.
17		Natick Sub Equipment Replacement	50	12	346	586	186	-	-	Transformer down payment deferred.
18		Division St. 61F2 Reconductoring (D-Line)	240	110	451	515	530	328	-	Delays in Engineering. Spending deferred.
19		Hopkins Hill 155F8_63F6 Fdr Tie Reloc	184	111	200	250	250	150	-	Delays in Engineering. Spending deferred.
20	CRIW - Other Area Study Projects - Total		1,883	369	6,106	9,559	3,668	478	-	
21		Phillipsdale Substation D Line *	100	78	-	-	-	-	-	--
22	East Bay - Other Area Study Projects -Total		100	78	-	-	-	-	-	
23		Eldred 45J3 Spirketing Recon D Line	53	80	170	593	-	-	-	Engineering started later than originally forecasted.
24		Dexter 36W44 Asset Replacement D Line	170	9	100	224	-	-	-	Spending deferred.
25		Gate II Equipment Replacement *	140	-	-	-	-	-	-	Re-studying this project for alignment with other work in the area.
26		Dexter #36 Equipment Replacement	83	2	200	752	-	-	-	Spending deferred.
27	Newport - Other Area Study Projects - Total		446	91	470	1,569	-	-	-	
28		Centredale Substation D Sub **	350	317	-	-	-	-	-	--
29		Centredale Substation D Line *	150	11	-	-	-	-	-	Engineering timeline pushed material procurement and construction out.
30	NWRI - Other Area Study Projects - Total		500	327	-	-	-	-	-	
31		Auburn Substation 4kV Conversions *	492	-	-	-	-	-	-	Spending deferred.
32		Getaways	-	-	-	-	-	-	90	--
33		East George 77J2 Conversion	-	-	-	-	-	-	170	--
34		Geneva - Modular	-	-	-	-	-	-	340	--
35		Knightsville - Modular	-	-	-	-	-	-	135	--
36	Providence - Other Area Study Projects - Total		492	-	-	-	-	-	735	
37		Tiverton Substation	75	6	396	2,148	-	-	-	Spending deferred.
38	Tiverton - Other Area Study Projects - Total		75	6	396	2,148	-	-	-	
39		Wood River Substation	-	-	-	-	1,307	2,614	2,058	--
40		Westerly Asset Condition	-	-	-	-	-	304	478	--
41	SCW - Other Area Study Projects - Total		-	-	-	-	1,307	2,917	2,536	
42	**Total Asset Condition Other Area Study Projects**		**4,327**	**1,831**	**8,150**	**15,642**	**7,473**	**5,417**	**4,427**	

* Project reclassified to a separate line item in the FY 2026 ISR 5 Year Investment Plan.
** Project reclassified to a Major Project Separately Tracked in the FY 2026 ISR 5 Year Investment Plan.

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Five Year Budget with Details – FY 2025 Updates
For the Twelve Months Ending March 31, 2025
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			FY 2025		**FY 2026 ISR 5 Year Investment Plan**					
Line Number	**Area Study**	**Project**	**Budget**	**Actual**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**Explanation of FY 2025 variances more than 10%**
1	**System Capacity & Performance - Other Area Study Projects Detail**									
2		Staples #112 Reliability Improvements	340	-						--
3		Staples #112 Reliability 112W43	-	14	75	1,599	-	-	-	Shifted back to original scope after no NWA bids received.
4		Staples #112 Reliability 112W44	340	86	1,524	569	-	-	-	Spending reduced to engineering only, construction deferred to FY26.
5	BSVS - Other Area Study Projects - Total		680	100	1,599	2,168	-	-	-	
6		Natick 29F1 Reconductoring	208	185	-	-	-	-	-	--
7		2232 Panto Rd. ERR	333	(20)	-	-	-	-	-	Panto Rd completed in FY24, budget s/h/b for Industrial Dr.
8		2232 Industrial Dr. ERR	-	162	-	-	-	-	-	Panto Rd completed in FY24, budget s/h/b for Industrial Dr.
9		Coventry 54F1 Reconductoring	900	1,006	1,000	2,647	-	-	-	--
10		Chopmist 34F3 Stepdown Conversion	-	105	-	-	-	-	-	Closeout costs from previous year's project.
11	CRIW - Other Area Study Projects - Total		1,441	1,438	1,000	2,647	-	-	-	
12		Bristol D Sub and D Line	84	56	241	1,591	-	-	-	--
13	East Bay - Other Area Study Projects -Total		84	56	241	1,591	-	-	-	
14		Jamestown Capacitor Bank	100	-	-	-	-	-	-	No spend, but will be recorded in Load Relief Blkt due to $ amount.
15		Eldred 45J4 Dline	65	-	-	-	-	-	-	No spend, but will be recorded in Load Relief Blkt due to $ amount.
16		37K22 and 37K33 Reconfiguration	235	-	-	352	-	-	-	Spending deferred.
17		Newport 203W7 Conversion Dline	64	-	123	-	-	-	-	Spending deferred.
18		65J2 Feeder Upgrade D-Line	329	85	728	593	-	-	-	Spending deferred.
19	Newport - Other Area Study Projects - Total		793	85	851	945	-	-	-	
20		NWRI Common Items - Area Study	-	14	-	-	-	-	-	Closeout costs from previous year's project
21		Nasonville #127 Sub (D Line)	108	563	123	230	-	-	-	UG cable materials received.
22		Nasonville Expansion Woonsocket D-L	-	121	1,300	-	-	-	-	New project relocating D Line from under Woonsocket Sub.
23	NWRI - Other Area Study Projects - Total		108	698	1,423	230	-	-	-	
24		Lafayette 30F2 Feeder Tie	285	49	500	1,032	-	-	-	Delays in design drawings.
25		Wakefield 17F2 Feeder Upgrade D-Line	286	2	500	1,033	-	-	-	Delays in design drawings.
26		Wakefield 17F2 Feeder Upgrade D-Sub	166	-	451	428	-	-	-	Delays in design drawings.
27		Wakefield 17F3 Feeder Relief	130	0	677	85	-	-	-	Delays in design drawings.
28		Peacedale 59F3 Feeder Relief	456	0	500	1,875	-	-	-	Delays in design drawings.
29		Lafayette 30F2 Feeder Upgrade	361	26	500	1,335	-	-	-	Delays in design drawings.
30	SCE - Other Area Study Projects - Total		1,684	78	3,128	5,788	-	-	-	
31		Kenyon 68FS Extension	532	347	532	-	-	-	-	Delays in receiving easements.
32		Chase Hill Common – 155F8 Reconductoring (	200	-	200	3,429	2,193	1,717	-	
33		Kenyon Common Items	195	-	-	-	-	-	-	Spending will be included in Load Relief Blanket.
34		Langworthy Corner Feeder Ties	-	-	-	728	1,456	1,456	-	--
35		Wood River 85T2 Extension	-	-	-	893	1,839	1,895	-	--
36	SCW - Other Area Study Projects - Total		927	347	732	5,050	5,488	5,068	-	
37	**Total System Capacity & Performance Other Area Study Pro**		**5,717**	**2,801**	**8,974**	**18,419**	**5,488**	**5,068**	**-**	

* Project reclassified to a separate line item in the FY 2026 ISR 5 Year Investment Plan.
** Project reclassified to a Major Project Separately Tracked in the FY 2026 ISR 5 Year Investment Plan.

Attachment F

Damage/Failure Detail by Work Type
For the Twelve Months Ending March 31, 2025
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Fiscal Year Ending March 31, 2025					
Line Number	Description	D Line Blanket	Property Damage	D Sub Blanket	Specifics	Storms	Total
1	ACNW Vault 72 Reconstruction				$597		$597
2	Faults	1,898					1,898
3	Monthly Confirming Work	11,414					11,414
4	Nasonville Failure				3,600		3,600
5	Westerly Spare Transformer				452		452
6	OH & UG Elec Distribution	2,318					2,318
7	Other			467	42		509
8	Property Damage		1,546				1,546
9	Storms					4,348	4,348
10	**Total**	**$15,630**	**$1,546**	**$467**	**$4,691**	**$4,348**	**$26,681**

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

Attachment G

Separately Tracked Major Projects
For the Twelve Months Ending March 31, 2025

Dyer Street Substation
Project Phase/Estimate Grade: Construction

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Dyer Street Substation	$15	$(39)	$15,406	$15,700

The demolition of the building is the only remaining significant activity for this project. Asbestos abatement has been completed and mobilization for the demolition started in April. Demolition is scheduled to be completed in July.

Please see the Company's response to PUC 6-4 in Docket 22-53-EL (First Quarterly Report) for a full explanation of the history of cost increases on the Dyer Street Substation project.

Admiral Street Substation
Project Phase/Estimate Grade: Detailed Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Admiral Street Substation	$5,513	$5,360	$12,381	$16,108

During FY 2025, major materials were procured for construction. Delays in procurement negotiations for long lead materials during FY 2024 required shifting expected payment milestones into FY 2025 and FY 2026. The temporary transformer was put into service in FY 2025, allowing the offloading of existing equipment which will be removed. The schedules for the substation work and other dependent non-major projects have been updated.

A construction grade estimate will be completed in December 2025.

Kingston Substation
Project Phase/Estimate Grade: Preliminary Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Kingston Substation	$400	$55	$16,806	$24,773

The Kingston Substation is in the Preliminary Engineering Phase. A revised conceptual level estimate incorporating inflation using the Handy Whitman indices was received in September 2024 and totaled $24.8 million for capital. Engineering and procurement of long lead materials has been delayed.

At an Open Meeting that occurred on March 29, 2025, and as part of the FY 2026 Electric ISR Plan filed under Docket No. 24-54-EL, the Public Utilities Commission directed the Company to remove the Kingston Substation project from the FY 2026 budget because it found that it is premature to include this project as eligible for ISR cost recovery. The Company is continuing to provide the project's forecasted capital spending as of March 31, 2025. The total project forecast is subject to change.

Phillipsdale Substation
Project Phase/Estimate Grade: Preliminary Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Phillipsdale Substation	$100	$792	$19,332	$19,332

During FY 2025, an engineering design firm was onboarded to begin final engineering and procurement of long lead material items. Capital spending for the year was $0.8 million and included the initial payment for the substation transformer, made in March 2025.

At an Open Meeting that occurred on March 29, 2025, and as part of the FY 2026 Electric ISR Plan filed under Docket No. 24-54-EL, the Public Utilities Commission directed the Company to remove the Phillipsdale Substation project from the FY 2026 budget because it found that it is premature to include this project as eligible for ISR cost recovery. The Company is continuing to provide the project's forecasted capital spending as of March 31, 2025. The total project forecast is subject to change.

Apponaug Substation
Project Phase/Estimate Grade: Preliminary Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Apponaug Substation	$150	$208	$5,770	$9,489

During FY 2025, an engineering design firm was onboarded to begin final engineering. The total project forecast was increased to $9.5 million based on a review of area study estimates and adjusted using Handy Whitman inflation indices.

Hospital Substation
Project Phase/Estimate Grade: Preliminary Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Hospital Substation	$320	$41	$5,360	$9,411

Through FY 2025, the Company worked on the engineering scope of work and major material specifications for the Hospital Substation. Actual spending was less than budgeted because initial payments for long lead materials were not made. During the Study Phase, the project's forecast was revised due to the identification of additional scope to improve the system reliability by replacing the switch gear at this substation which serves Newport Hospital. It was determined that the entire switch gear must be replaced.

At an Open Meeting that occurred on March 29, 2025, and as part of the FY 2026 Electric ISR Plan filed under Docket No. 24-54-EL, the Public Utilities Commission directed the Company to remove the Hospital Substation project from the FY 2026 budget because it found that it is premature to include this project as eligible for ISR cost recovery. The Company is continuing to provide the project's forecasted capital spending as of March 31, 2025. The total project forecast is subject to change.

East Providence (First Street) Substation
Project Phase/Estimate Grade: Detailed Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
East Providence Substation	$2,685	$2,078	$19,670	$19,670

Detailed engineering began in August 2024. The transformer and metal-clad switchgear have been ordered, but the milestone payment for the transformer was shifted from FY 2025 to FY 2026.

Because the substation site is a former gas storage facility, additional site investigation and soil borings were performed this year. The need for additional remediation was identified and will be incorporated into construction grade estimate.

In March 2024, the Company received an updated total project estimate of $19.7 million, with a variance range of -25% to +50%. The initial plan was to receive the construction grade estimate by April 2025; however, due to delays getting a new engineering firm on the project, this has been extended to October 2025.

Nasonville Substation
Project Phase/Estimate Grade: Detailed Engineering

Capital Spend *($000s)*	**FY 2025**		**Total Project**	
	Budget	**Actual**	**Estimate**	**Forecast**
Nasonville Substation	**$3,566**	**$5,676**	**$10,786**	**$14,800**

The Company continues material procurement and construction activities for the expansion of the Nasonville Substation. The transformer was received in January 2025 and energized in April 2025.

The capital construction grade estimate was received in December 2024 and is $14.8 million +/- 10%. Based on the delayed delivery of the station circuit switchgear, the project is expected to be completed in early 2027.

Attachment G
Major Project Life Cycle

	(a)	(b)
Line Number	**Stage**	**Milestones During This Stage:**
1	Study Phase	• Consistent estimating methods across all alternatives. • Subject matter expert consultation with field visits to develop scopes. • Desktop environmental, subsurface, and permitting review. • Project Management consultation to develop construction execution assumptions. • Depending on the status of the project, there may be additional revisions to study estimate depending on available information.
2	Preliminary Engineering	• Engineering consultant onboarded. • Sound study. • Ground borings. • Scope refined. • Preliminary outage planning. • Detailed design begins. • Estimates are refined as additional information becomes available.
3	Detailed Engineering	• Scope/drawings ready for bid. • Material procurement • Final design complete • Permits received (in parallel with construction resource procurement) • Estimates are refined as additional information becomes available.
4	Construction Resource Procurement	• RFP Issued • Negotiations/Clarifications with Bidders • Construction Contractor Awarded • Estimate (+/- 10%) refined – budget discipline applied
5	Construction	• Construction commences. • Construction complete. • Change orders reviewed/approved.
6	Closeout	• Lessons learned documented. • Project financially closed.

Attachment H

Meter Purchases
For the Twelve Months Ending March 31, 2025

	(a)	(b)	(c)
	Quantity of Meters Purchased		
Line	Type	Description	Quantity
1	METER	CENTRON - 2S 240V CL200	3,681
2	METER	CENTRON - 12S ERT CL200	558
3	METER	CENTRON - 16S CL320	36
4	METER	CENTRON - 3-ERT AMR	360
5	METER	ACLARA KV2C METER 9S	46
6	METER	ACLARA KV2C METER 5S	20
7	METER	TRANSDATA MARKV FM5	3
8	INSTRUMENT TRANSFORMER	CUR 600v ASTRA (GEC DURHAM)	108
9	INSTRUMENT TRANSFORMER	CUR GENERAL ELECTRIC 34.5KV	11
10	INSTRUMENT TRANSFORMER	CUR RITZ 600v	0
11	INSTRUMENT TRANSFORMER	CUR RITZ 34.5KV	69
12	INSTRUMENT TRANSFORMER	VT RITZ 4KV	3
13	INSTRUMENT TRANSFORMER	VT RITZ 600v	371
14	INSTRUMENT TRANSFORMER	VT RITZ 15kV	40
15	INSTRUMENT TRANSFORMER	CUR RITZ 8.7kV	6
16	INSTRUMENT TRANSFORMER	CUR RITZ 15kV	6
17	INSTRUMENT TRANSFORMER	CUR RITZ 25kV	38
18	INSTRUMENT TRANSFORMER	VT RITZ 7.2kV	72
19	INSTRUMENT TRANSFORMER	VT RITZ 25kV	16
20	INSTRUMENT TRANSFORMER	VT RITZ 8.4kV	72
21	INSTRUMENT TRANSFORMER	VT 600v RITZ	21
22	INSTRUMENT TRANSFORMER	CUR 600v RITZ	556
23		**TOTAL**	**6,093**

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, 2025
Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
Service List as of 2/14/2025

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	amarcaccio@pplweb.com;	401-784-4263
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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
Conservation Law Foundation (CLF) James Rhodes, Esq. Conservation Law Foundation 235 Promenade Street Suite 560, Mailbox 28 Providence, RI 02908	jrhodes@clf.org;	401-225-3441
File an original & 9 copies w/ PUC: Stephanie De La Rosa, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	stephanie.delarosa@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Kristen.L.Masse@puc.ri.gov;	401-780-2107
Matt Sullivan, Green Development LLC	ms@green-ri.com;	
Emily Koo, Director, Acadia Center	EKoo@acadiacenter.org;	

Attachment 2

2024 Electric Service Quality Report

Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com;

280 Melrose Street
Providence, RI 02907
Phone 401-316-7429

Rhode Island Energy™
a PPL company

May 1, 2025

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 3628 – 2024 Service Quality Report (Electric Operations)

Dear Ms. De La Rosa:

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, 2024 through December 31, 2024 (the "2024 Service Quality Report" or "Report"). Based on actual performance results, the Company has calculated a total penalty of $117,371 for calendar year 2024.

The 2024 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. In addition, the 2024 Service Quality Report includes a new penalty-only performance standard for meter reading and billing, which includes categories for estimated bills and bills successfully issued beginning in September 2024, in compliance with the PUC's rulings at its August 1, 2024 Open Meeting in this docket.[2] 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 six categories, a

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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] In Docket No. 22-49-EL, the PUC ordered the Company to file an updated SQ Plan that included the following revised metrics: (1) meter reading and billing; (2) faster outage notification; (3) network speed; (4) trouble, non-outage; and (5) customer satisfaction, which the Company submitted on December 27, 2023. The PUC approved, with modifications, a meter reading and billing metric at its August 1, 2024 Open Meeting, and approved, with modifications, the other metrics at its October 31, 2024 Open Meeting. Only the meter reading and billing metric is applicable to the 2024 Service Quality Report, and the Company has prorated the monthly results beginning September 2024. The Company will be submitting an updated SQ Plan in compliance with the PUC's Open Meeting decisions in this docket under separate cover.

penalty is assessed. The Company cannot earn a monetary award for exceeding expectations; however, it can accrue offsets for good performance in one category (except for the meter reading and billing categories), 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.[3]

For 2024, the Company incurred a penalty of $138,000 for the customer contact category of the customer service standard and $7,360 for the bills successfully issued category of the meter reading and billing standard. The Company earned an offset of $27,989 for the interruption frequency category. The Company's performance fell within an acceptable regulatory range for each of the other three categories, resulting in a total penalty of $117,371. 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; (4) Calculates the number of bills issued each month that were not correctly calculated beginning in September 2024;[4] and (5) 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 matter. If you have any questions, please contact me at 401-316-7429.

Sincerely,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosure

cc: Docket No. 3628 Service List

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

[4] This is a new reporting requirement in compliance with the PUC's rulings issued at is August 1, 2024 Open Meeting in this docket.

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

2024 Service Quality Report

May 1, 2025

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, CUSTOMER SERVICE AND METER READING/BILLING 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 were three Major Event Days that occurred during 2024. These were on January 13, June 26 and December 11.

2024 Total Frequency (SAIFI) Standard		**2024 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	0.83	$27,989
Less than 0.75	$229,000		

2024 Duration (SAIDI) Standard		**2024 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	60.98	$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's 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.

2024 Customer Contact Standard		**2024 Customer Contact Results**	
Percent Satisfied	(Penalty)/Offset	Percent Satisfied	Annual (Penalty)/Offset
Less than 74.4%	($184,000)		
74.4%-78.7%	linear interpolation	75.5%	($138,000)
78.8%-87.6%	$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.

2024 Calls Answered Standard		**2024 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	79.9%	$0
90.5% - 100.0%	linear interpolation, to maximum of $46,000		

METER READING AND BILLING STANDARDS

Bills Based on Estimated Usage

Rhode Island Energy will report annually on the percentage of bills based on estimated usage per month.

Monthly Percentage of Bills Based on Estimated Usage	Monthly (Penalty)/Offset
≥ 17.6%	($34,000)
< 17.6% and > 1.6%	Linear interpolation
≤ 1.6%	$0

Please see the table below for the 2024 Monthly Results beginning in September 2024.[1]

	(a) Month	(b) Result	(c) (Penalty)/Offset
1	September	0.9%	-
2	October	0.7%	-
3	November	0.9%	-
4	December	0.8%	-
5	Annual Penalty		-

[1] As ordered in Docket 22-49-EL: "The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period." Rhode Island Energy exited its Transition Services Agreement ("TSA") with National Grid in August 2024.

Bills Successfully Issued

The bills successfully issued performance standard reflects the monthly number of bills issued as a percentage of the total number of bills that should be issued monthly.

Bills Successfully Issued Standard

Monthly Percentage of Bills Successfully Issued	Monthly (Penalty)/Offset
≤ 90%	($16,000)
> 90% and < 100%	Linear interpolation
≥ 100%	$0

Please see the table below for the 2024 Monthly Results beginning in September 2024.[2]

	(a) Month	(b) Result	(c) (Penalty)/Offset
1	September	98.4%	(2,560)
2	October	98.8%	(1,920)
3	November	98.9%	(1,760)
4	December	99.3%	(1,120)
5	Annual Penalty		(7,360)

[2] As ordered in Docket 22-49-EL: "The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period." Rhode Island Energy exited its Transition Services Agreement ("TSA") with National Grid in August 2024.

SECTION 2: CALCULATION OF PENALTY/OFFSET

	Performance Standard	Potential Penalty (a)	Potential Offset (b)	2024 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)
1	Reliability - Frequency	$ 916,000	$ 229,000	0.83	1.18	1.05	0.94	0.84	0.75	$27,989
2	Reliability - Duration	$ 916,000	$ 229,000	61.0	89.9	71.9	57.5	45.9	36.7	$0
3	Customer Service - Customer Contact Survey	$ 184,000	$ 46,000	75.5%	74.4%	78.8%	83.2%	87.6%	92.0%	($138,000)
4	Customer Service - Telephone Calls Answered	$ 184,000	$ 46,000	79.9%	53.5%	65.8%	78.1%	90.4%	100.0%	$0
5	Meter Reading/Billing - Estimated Bills	$ 136,000	$ -	N/A - Monthly	17.6%	-	-	-	1.6%	$0
6	Meter Reading/Billing - Bills Successfully Issued	$ 64,000	$ -	N/A - Monthly	90.0%	-	-	-	100.0%	$ (7,360)
	Total Penalty/Offset	$ 2,400,000	$ 550,000							($117,371)

Notes:

1. Columns (a), (b), and (d)-(h) are per the Amended Electric Service Quality Plan, RIPUC Docket No. 3628.
2. Column (c) represents the actual 2024 annual results for the performance standards listed in the first column.
3. Rows 5 and 6 are related to the Meter Reading/Billing monthly metrics that began in September 2024. Column (a) is prorated to show four months of potential penalties. Monthly results and calculations of penalties are outlined on the specific pages related to these metrics in the report.

For Rows 1 through 5, 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 2024 feeder ranking results on June 7, 2024, the second quarter results on August 8, 2024, and the third and fourth quarter results on March 7, 2025.

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 2024, with the final report for the 13 months ending July 2024 filed on August 21, 2024.

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

   Results: During 2024, the Company's annual meter reading performance (as an average of monthly percentage of meters read) was 99.03% compared to 98.98% in 2023, and 98.88% during 2022. The following table details the percentage of meters read per month for 2024, 2023 and 2022.

Monthly Percentage of Meters Read

	(a)	(b)	(c)	(d)
	Month	**2024**	**2023**	**2022**
1	January	99.10%	98.92%	98.71%
2	February	99.13%	98.96%	98.71%
3	March	99.16%	98.93%	98.75%
4	April	99.21%	98.98%	98.90%
5	May	99.22%	99.04%	98.96%
6	June	99.17%	99.03%	98.95%
7	July	99.09%	99.00%	98.95%
8	August	98.94%	99.05%	99.12%
9	September	99.08%	99.03%	98.96%
10	October	99.08%	99.13%	98.76%
11	November	98.40%	99.14%	98.95%
12	December	98.76%	98.49%	98.87%
13	**YTD Average**	**99.03%**	**98.98%**	**98.88%**

4. **Reporting Requirement:** The Company will report on the number of bills issued each month that were not correctly calculated.

   Results: Please see the table below for the number of electric bills each month that were not correctly calculated starting in September 2024.

	Month	**# of Bills Not Correctly Calculated**
1	September	323
2	October	732
3	November	938
4	December	3,812

5. **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[3] 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 2024, the TMED value was 5.65 minutes of SAIDI (using IEEE Std. 1366-2012 methodology). There were three major storm days that exceeded this threshold in 2024. These were on January 13, June 26, and December 11. The storm details are described below.

[3] 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.

January 13, 2024 Storm

1. **Start date/Time of event:**
   The storm began on January 13, with scattered interruptions starting at 5:00 a.m. in the early morning of January 13. The peak was around 07:25 a.m. on January 13. The peak reached 14,418 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**
   The Company secured a total of 292 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 128 external crews and 164 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 - 48 crews
   External Overhead Line - 151 crews
   Internal Trouble Worker - 54 crews
   Internal Wire Down - 39 crews
   Internal Underground - 9 crews
   Internal Substation - 29 crews
   Contractor Forestry - 50 crews
   Contractor Transmission - 6 crews
   Internal Damage Appraiser - 12 crews
   Contractor Damage Appraiser - 20 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 supplier was on January 13.

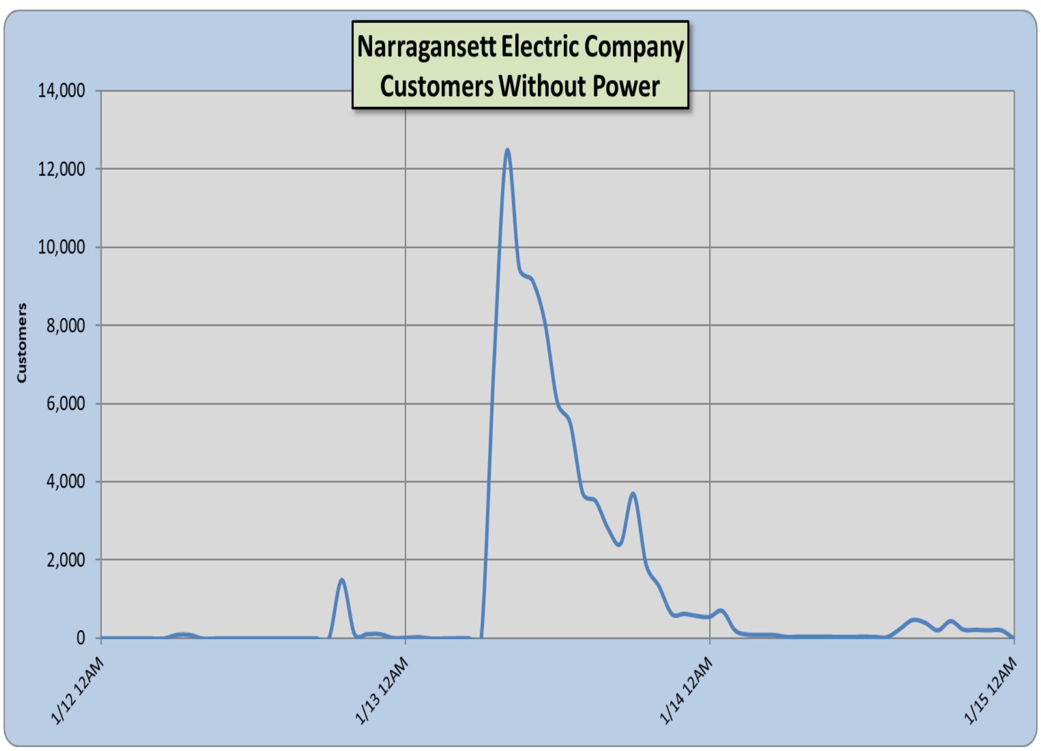
6. **Inventory levels: Pre-event/daily/post-event:**

PLANT#	1101 Alloc.
LOCATION	RI Allocated Inventory Balance @ PLS
1/13/2024	$26.2M

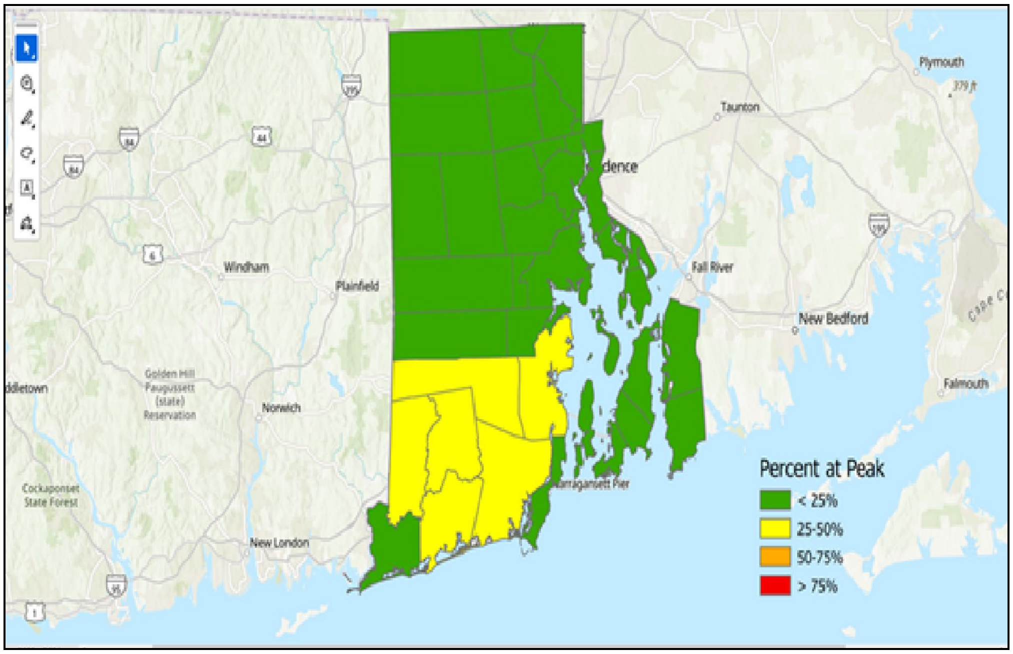
7. **Date/Time of request for external crews:**
Given the potential magnitude of the storm and forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all its regional preparation for the storm, consistent with its Emergency Response Plan.

8. **Date/Time of external crew assignment:**
External crews were assigned to work around 8:00 p.m. on January 12.

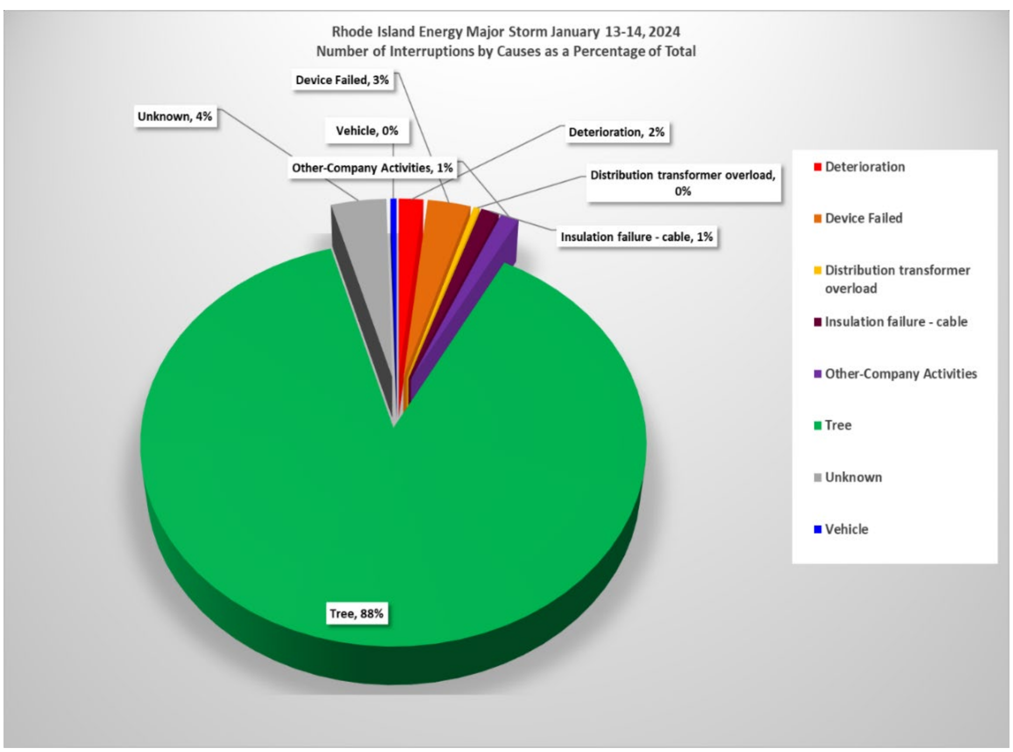
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause



12. Weather impact on restoration:
The storm was a short duration weather event that resulted in moderate damage to the Company's electrical system. The storm brought strong wind throughout the state. Peak wind gusts were generally in the 60-65 mph range, with Providence experiencing a peak gust of 52 mph. The Town of Charlestown was affected most heavily with approximately 84 percent of customers impacted by the event, also of note were the Towns of Hopkinton and Richmond also impacted with approximately 70 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:

<u>January 13, 2024</u>
On January 13, 2024, Rhode Island experienced 109 interruptions that affected 21,344 customers and 4,812,912 customer minutes of interruption. On average these interruptions resulted in 0.0419 SAIFI, 9.45 minutes of SAIDI. Since a SAIDI value of 9.45 minutes exceeded the threshold value of 5.65 minutes, January 13 qualified as a Major Event Day under the IEEE methodology.

<u>January 14, 2024</u>
On January 14, 2024, Rhode Island experienced 21 interruptions that affected 3,811 customers and 244,196 customer minutes of interruption. On average these interruptions resulted in 0.01 SAIFI, 0.48 minutes of SAIDI. Since a SAIDI value of 0.48 minutes did not exceed the threshold value of 5.65 minutes, January 14 did not qualify as a Major Event Day under the IEEE methodology.

June 26, 2024 Storm

1. **Start date/Time of event:**
The storm began on June 26, with scattered interruptions starting at 5:00 p.m. in the late afternoon. The peak was around 01:31 a.m. on June 27. The peak reached 26,685 customers interrupted.

The Company secured a total of 141 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 105 external crews and 36 internal crews. The internal and external field crew numbers included transmission and distribution overhead line, forestry, substation, underground, wires down, and damage assessment personnel.

2. **Number/Location of crews on duty (both internal and external crews):**
The Company secured a total of 141 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 105 external crews and 36 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.

<u>Crew Type</u>
Internal Overhead Line - 77 crews
External Overhead Line - 114 crews
Internal Trouble Worker - 54 crews
Contractor Forestry - 118 crews
Contractor Damage Appraiser - 21 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 the material supplier was on June 27.

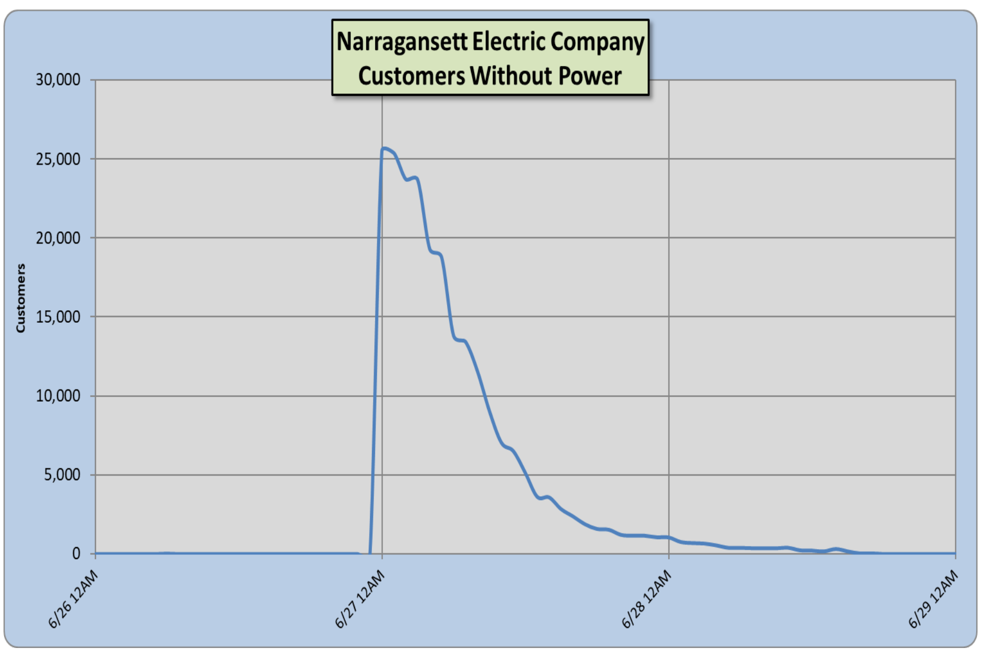
6. **Inventory levels: Pre-event/daily/post-event:**

PLANT#	1101 Alloc.
LOCATION	RI Allocated Inventory Balance @ PLS
6/26/2024	$46M

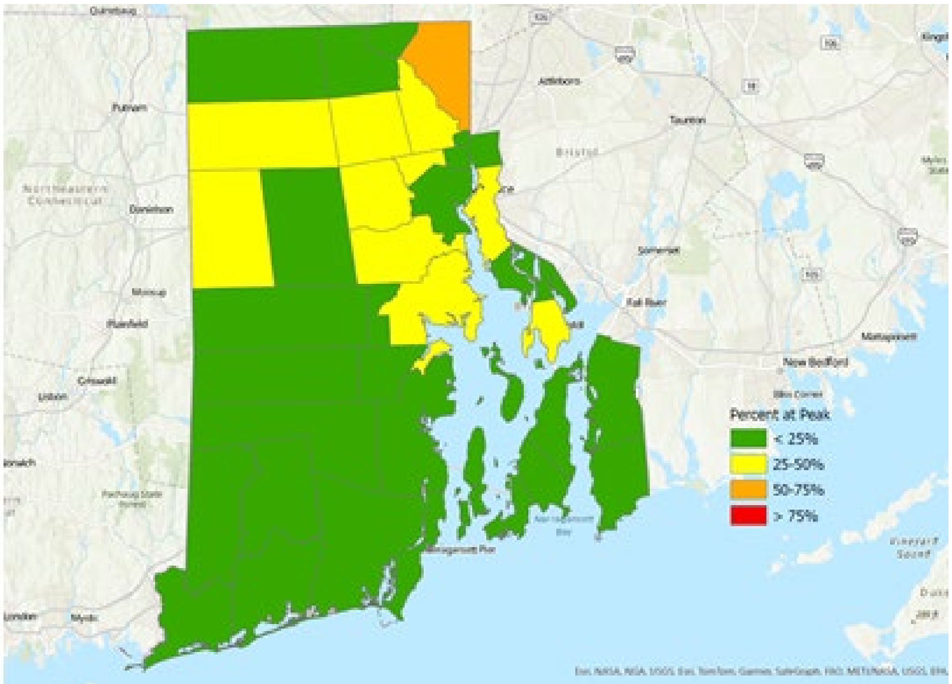
7. **Date/Time of request for external crews:**
Given the potential magnitude of the storm and forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all its regional preparation for the storm, consistent with its Emergency Response Plan.

8. **Date/Time of external crew assignment:**
External crews were assigned to work around 5:00 a.m. on June 26.

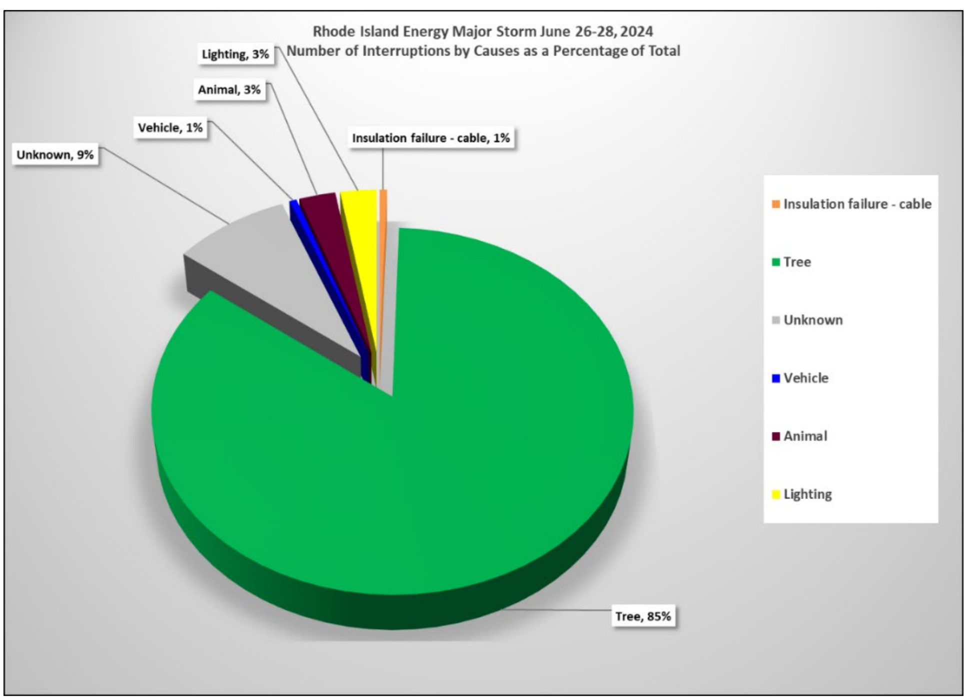
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause:



12. Weather impact on restoration:
The storm was a short duration weather event that resulted in moderate damage because it was a no notice tornado that impacted limited areas of the state with no other significant damage outside those areas. Peak wind gusts were generally in the 25-30 mph range, with Providence experiencing a peak gust of 44 mph. The Town of Cumberland was affected most heavily with approximately 58 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:

June 26, 2024
On June 26, 2024, Rhode Island experienced 80 interruptions that affected 26,971 customers and 13,945,139 customer minutes of interruption. On average these interruptions resulted in 0.053 SAIFI, 27.39 minutes of SAIDI. Since a SAIDI value of

27.39 minutes exceeded the threshold value of 5.65 minutes, June 26 qualified as a Major Event Day under the IEEE methodology.

June 27, 2024
On June 27, 2024, Rhode Island experienced 26 interruptions that affected 509 customers and 123,468 customer minutes of interruption. On average these interruptions resulted in 0.001 SAIFI, 0.24 minutes of SAIDI. Since a SAIDI value of 0.24 minutes did not exceed the threshold value of 5.65 minutes, June 27 did not qualify as a Major Event Day under the IEEE methodology.

June 28, 2024
On June 28, 2024, Rhode Island experienced 6 interruptions that affected 263 customers and 26,242 customer minutes of interruption. On average these interruptions resulted in 0.0005 SAIFI, 0.05 minutes of SAIDI. Since a SAIDI value of 0.05 minutes did not exceed the threshold value of 5.65 minutes, June 28, 2024 did not qualify as a Major Event Day under the IEEE methodology.

December 11, 2024 Storm

1. **Start date/Time of event:**
The storm began on December 11, with scattered interruptions starting at 9:00 a.m. in the early morning of December 11. The peak was around 4:42 p.m. on December 11. The peak reached 13,416 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**
The Company secured a total of 204 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 134 external crews and 70 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 - 66 crews
External Overhead Line - 200 crews
Internal Trouble Worker - 20 crews
Internal Wire Down - 39 crews
Internal Underground - 20 crews
Internal Substation - 34 crews

Contractor Forestry - 192 crews
Contractor Transmission - 26 crews
Contractor Damage Appraiser - 42 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 supplier was on December 11th.

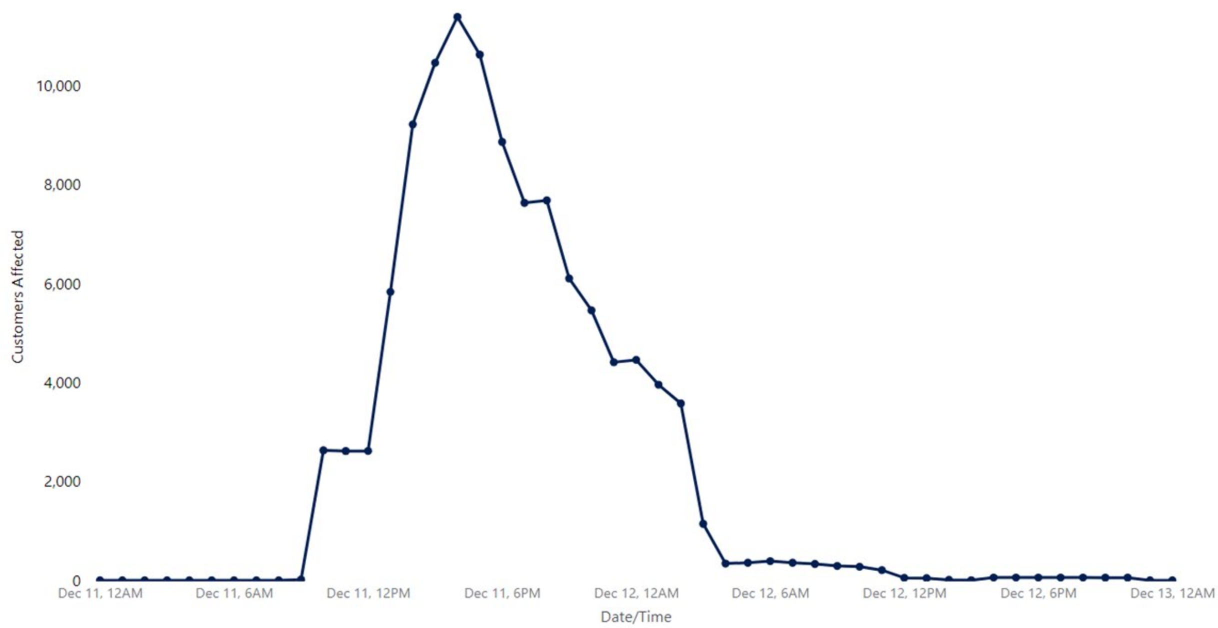
6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1101 Alloc.
LOCATION	RI Allocated Inventory Balance @ PLS
12/11/2024	$41.1M

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.

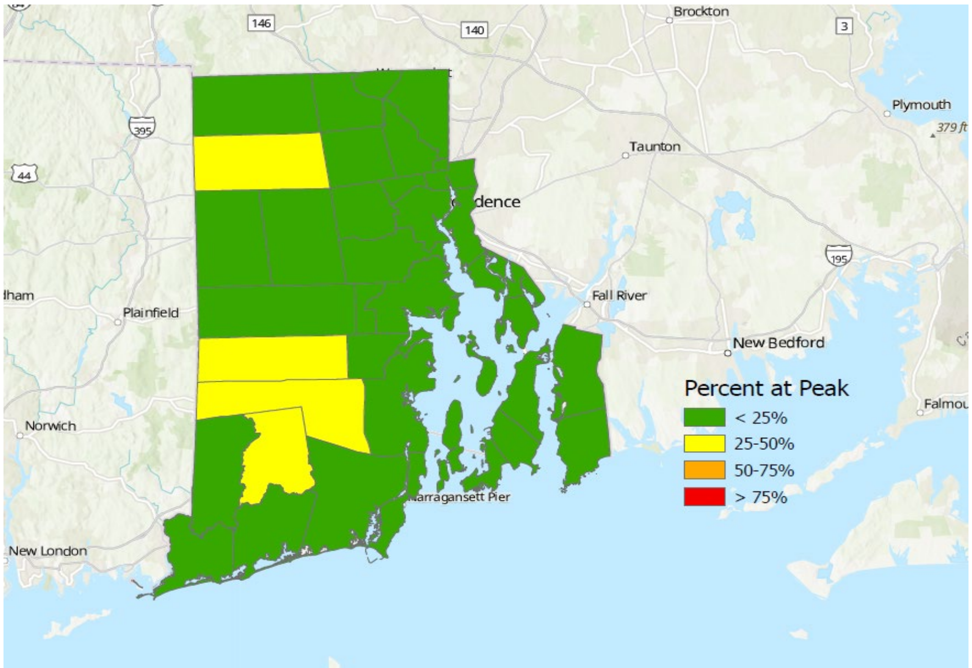
8. **Date/Time of external crew assignment:**
External crews were assigned to work around 7:00 a.m. on December 11th.

9. # of customers out of service by hour: [4]

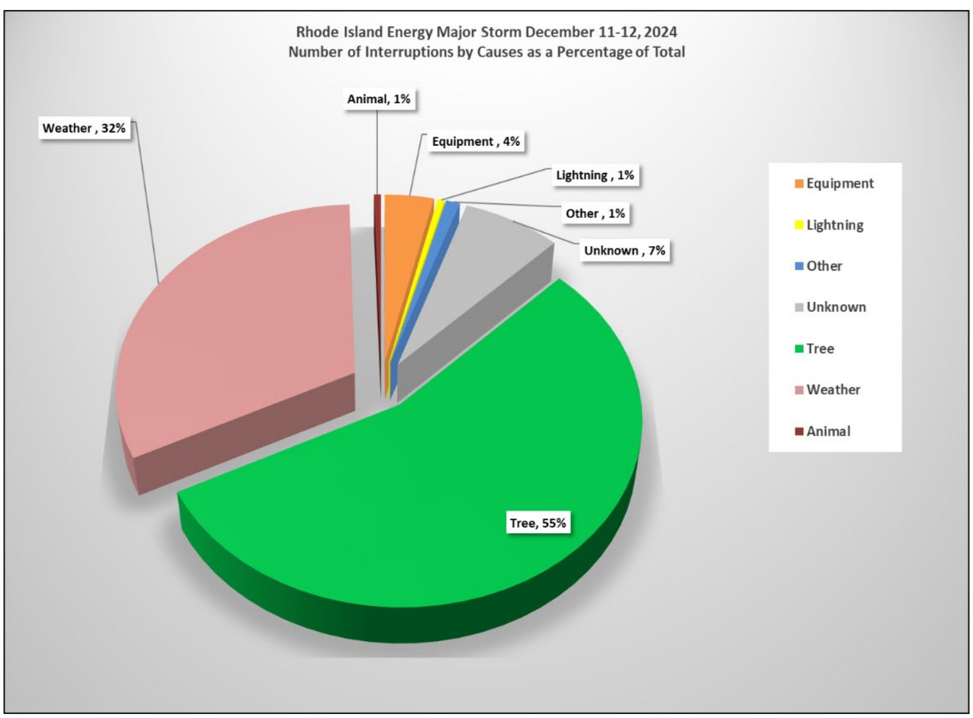


[4] Please note, the chart in 9 of the December 11, 2024 Storm report is different the prior storm reports as the Rhode Island Energy website and data tracking are new systems since the August 2024 system cutover and the majority of remaining transition services under the Transition Services Agreement between National Grid USA Service Company, Inc. and the Company ended.

10. Impacted area:



11. Cause:



12. Weather impact on restoration:

Ultimately, the storm was a short duration weather event that resulted in moderate damage that impacted areas across the state with no significant damage. Peak wind gusts were generally in the 45-55 mph range, with Providence experiencing a peak gust of 55 mph. The Town of Chopmist was affected most heavily with approximately 14 percent of customers affected 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 switches. 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:

<u>December 11, 2024</u>

On December 11, 2024, Rhode Island experienced 91 interruptions that affected 20,639 customers and 3,390,258 customer minutes of interruption. On average these interruptions resulted in 0.040 SAIFI, 6.602 minutes of SAIDI. Since a SAIDI value of 6.602 minutes exceeded the threshold value of 5.65 minutes, December 11 qualified as a Major Event Day under the IEEE methodology.

December 12, 2024

On December 12, 2024, Rhode Island experienced 9 interruptions that affected 595 customers and 76,929 customer minutes of interruption. On average these interruptions resulted in 0.001 SAIFI, 0.15 minutes of SAIDI. Since a SAIDI value of 0.15 minutes did not exceed the threshold value of 5.65 minutes, December 12 did not qualify 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, 2025
Date

Rhode Island Energy – Electric Service Quality Plan – Docket 3628 Service List Updated 5/1/2025

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	Cynthia.WilsonFrias@puc.ri.gov;	
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PRE-FILED DIRECT TESTIMONY

OF

JEFFREY D. OLIVEIRA

August 1, 2025

Table of Contents

I. <u>Introduction</u>

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 Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") 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 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 testified before the PUC on numerous occasions including the Company's FY 2026 Electric Infrastructure, Safety, and Reliability ("ISR") Plan in Docket No. 24-54-EL; FY 2025 ISR Plan in Docket No. 23-48-EL; FY 2024 ISR Plan in Docket No. 22-53-EL; FY 2023 ISR Plan and Reconciliation in Docket No. 5209 as well as many other electric and gas filings.

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, 2024. That factor was based on a projected FY 2025 Electric ISR revenue requirement of $54,861,882 calculated using (i) the estimated ISR plant additions during the Company's FYs ended March 31, 2025 and 2024, (ii) 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, 2025, and (iii) the actual ISR additions during the Company's Fiscal Years ended March 31, 2018, 2019, 2020, 2021, 2022, and 2023, which were incremental to the levels reflected in rate base after the Company's last base distribution rate case (Docket No. 4770). On September 1, 2018, the new distribution base rates 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 2025 Electric ISR revenue requirement associated with actual FY 2025 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2025 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 2024 and 2023, a hold harmless adjustment, and a reduction for the adjustment related to the FY 2025 capital consolidated soft budget overspend.

The updated FY 2025 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, 2025.

As shown on Attachment JDO-1, Page 1, at Line 26, the updated FY 2025 ISR revenue requirement collectible through the Company's Electric ISR factor for the FY 2025 period, including updated tax deductibility adjustments and corrections to the FY 2023 and FY 2024 revenue requirements, totals $59,064,126. This is an increase of $4,202,244 from the projected FY 2025 Electric ISR revenue requirement of $54,861,882, previously approved by the PUC in this docket. This increase is primarily attributable to (1) a net increase in the FY 2024 and FY 2025 revenue requirement on a higher level of capital investment; (2) an increase in the actual effective FY 2025 property tax rate compared with the projected effective FY 2025 property tax rate in the FY 2025 ISR Plan; and (3) an increase to the revenue requirement for the updated FY 2023, FY 2024 and FY 2025 hold harmless adjustments as discussed in the testimony of Ms. Hawk. These increases were partially offset by (1) a net decrease to the FY 2018 through FY 2024 revenue requirements to reflect the removal of DG projects in the FY 2024 reconciliation that were not reflected in the FY 2025 approved revenue requirement; (2) a net decrease for the tax updates and corrections for FY 2023 and FY 2024 taxes as described in the testimony of Company Witness Natalie Hawk; (3) a decrease for an update to the FY 2024 retirements; (4) a decrease for lower actual O&M spend as compared to forecasted; and (5) a reduction to the revenue requirement for the adjustment related to the FY 2025 capital consolidated soft budget overspend.

Q. Are there any attachments to your testimony?

A. Yes, I am sponsoring the following attachments:

- Attachment JDO-1 — Revenue Requirement Summary and Calculation FY 2025 Electric Infrastructure, Safety, and Reliability Plan Reconciliation

- Attachment JDO-2 — FY 2025 Adjustment for Capital Consolidated Soft Budget Overspend

Q. Please describe how Attachment JDO-1 is structured.

A. Page 1 of Attachment JDO-1 summarizes the individual components of the updated FY 2025 ISR revenue requirement. Page 1, Column (a) reflects the approved FY 2025 Electric ISR Plan revenue requirement on projected VM and I&M program costs and incremental ISR capital investment as well as the projected FY 2025 property tax recovery adjustment. Page 1, Column (b) represents (1) the O&M components for FY 2025; (2) FY 2025 ISR revenue requirements for incremental FY 2018 through FY 2025 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, 23 and 26; (3) FY 2025 property tax adjustment on incremental capital not included in the Company's base rates in Docket No. 4770; (4) the reconciliation on Lines 15 through 18 of the approved FY 2023 and FY 2024 ISR revenue requirement for vintage FY 2023 and FY 2024 plant additions with the actual vintage FY 2023 and FY 2024 revenue requirement on those investments related to tax deductibility updates and corrections; (5) the hold harmless adjustments related to the impacts of the Acquisition; and (6) the FY 2025 capital budget overspend adjustment. As discussed in Ms. Hawk's testimony, the reconciliation in item (4) is necessary because the actual level of tax deductibility on FY 2024 investments was not known when the Company filed the FY 2024 ISR reconciliation and FY 2025 Electric ISR Plan proposals as well as corrections to prior years. A detailed calculation of the updated FY 2025 revenue requirement is presented on page 26 of Attachment JDO-1.

II. <u>Electric ISR FY2025 Revenue Requirement</u>

Q. Did the Company calculate the updated FY 2025 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the FY 2024 ISR factor reconciliation?

A. Yes, the Company calculated the updated FY 2025 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions. Similar to the FY 2024 filing, the calculation incorporates the approved weighted average cost of capital and depreciation rates from Docket No. 4770 and known tax deductibility percentages, and tax gains and losses on retirements for FY 2023 and FY 2024.

The updated FY 2025 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, 2024. A detailed description of the revenue requirement calculation employed can be found in the revenue requirement testimony included in the Company's FY 2025 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) an adjustment to the revenue requirement for FY 2025 capital consolidated soft budget overspend.

Q. Please summarize the change in the FY 2025 ISR revenue requirement proposed in this reconciliation filing as compared to the FY 2025 revenue requirement effective April 1, 2024, which was based on projected capital additions approved in the FY 2024 and FY 2025 ISR Plans.

A. As shown in Attachment JDO-1, Page 1, Line 26, column (c), the overall FY 2025 revenue requirement increase is $4,202,244, which is the net impact of: (1) a $1.0 million increase in the FY 2025 revenue requirement on vintage FY 2025 ISR capital additions mainly caused by $15 million higher capital investment placed into service compared to the amount projected in the approved FY 2025 Electric ISR Plan and an update to FY 2025 retirements; (2) a $5.5 million increase in the FY 2025 property tax recovery adjustment mainly driven by the higher actual tax rate in FY 2025 compared to the projected tax rate included in the previously filed FY 2025 Electric ISR Plan; and (3) a net $0.1 million increase in the FY 2025 revenue requirement on vintage FY 2024 Electric ISR capital additions mainly driven by higher actual FY 2024 capital additions compared to forecasted FY 2024 additions and the reflection of the DG project removal that was made in the FY 2024 Electric ISR revenue requirement reconciliation and updated FY 2024 cost of removal and retirements. These increases were offset in part by (1) a decrease of $0.2 million due to the true-up of FY 2023 and FY 2024 revenue requirement to reflect actual tax deductibility as described in Ms. Hawk's testimony; (2) a decrease of $1.0 million for the FY 2025 and FY 2024 income tax deductibility update from the FY 2025 Plan; (3) a net reduction to the FY 2025 revenue requirement of $0.2 million for FY 2018 through FY 2023 capital investments mainly related to the DG project removal; and (4) a $0.2 million decrease in O&M expense compared to the approved FY 2025 plan. Additionally, the FY 2025 revenue requirement was increased for the FY 2023, FY 2024 and FY 2025 tax hold harmless adjustment of $0.1 million as described in the testimony of Ms. Hawk and decreased for the FY 2025 capital consolidated soft budget overspend adjustment of $0.9 million as discussed below.

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 2025 ISR revenue requirement recoverable through the FY 2025 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, FY 2022, and FY 2023 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 distribution rates reflects a full year of revenue requirement because 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 distribution rates.

Q. Does the updated FY 2025 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 and FY 2024 revenue requirement reflected in the FY 2025 Electric ISR Reconciliation?

A. Yes. Please see the testimony of Ms. Hawk for a description of the tax updates reflected in the FY 2025 Electric ISR revenue requirement.

Q. Please summarize the updated FY 2025 Electric ISR revenue requirement.

A. As shown on Page 1 of Attachment JDO-1, the Company's FY 2025 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's Vegetation Management activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's Inspection &

Maintenance 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 Company witness Eric Wiesner. Line 4 reflects the actual FY 2025 revenue requirement related to O&M expenses of $13,922,884.

As shown on Page 1, at Line 19 of Attachment JDO-1, the FY 2025 revenue requirement associated with the Company's actual capital investment totals $47,976,168. As previously noted, the total FY 2025 capital investment component of revenue requirement includes (1) FY 2025 revenue requirement on vintages FY 2018 through FY 2025 ISR capital investments above or below the level of capital investment reflected in base distribution rates in Docket No. 4770; (2) the FY 2025 property tax recovery mechanism component; and (3) the FY 2023 and FY 2024 revenue requirement true-up for changes to previously estimated tax depreciation expense to align with the Company's FY 2024 tax return as well as corrections to prior year's formulas. The total actual FY 2025 Electric ISR Plan revenue requirement for both O&M expenses and capital investment of $61,899,052 is shown on Line 20. Additionally, the FY 2025 Revenue Requirement is adjusted for the FY 2023, FY 2024 and FY 2025 Hold Harmless adjustments on Lines 21, 22, and 23, as further described in the testimony of Ms. Hawk, and the FY 2025 capital consolidated soft budget overspend adjustment on Line 25. This results in a net FY 2025 Revenue Requirement of $59,064,126 on Line 26.

Q. Has the Company provided support for the actual level of FY 2025 ISR-eligible plant investments?

A. Yes. The description of the FY 2025 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 Mr. Wiesner. 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 Mr. Wiesner, the actual ISR eligible plant additions for FY 2025 totals $115.2 million associated with the Company's FY 2025 Electric 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 2025 revenue requirement, the lesser of these items was actual discretionary capital additions of $51,867,959, as shown on Attachment JDO-1, Page 39, Line 13, column (a), all of which 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 2025 revenue requirement, associated with the Company's actual FY 2018 through FY 2025 ISR eligible plant investments, totals $61,899,052. This amount includes the updated FY 2025 O&M components and revenue requirement on FY 2018 through FY 2025 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 and FY 2024 ISR revenue requirements on vintage FY 2023 and FY 2024 investments with the actual income tax deductibility on those investments and corrections to formulas as discussed in the testimony of Ms. Hawk.

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, 10, 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 2024 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 decrease the FY 2025 revenue requirement for the FY 2025 capital consolidated soft budget overspend.

A. As described in the testimony of Mr. Wiesner, the Company exceeded the 2.5 percent overspend allowance in the approved FY 2025 Electric ISR budget by $8.8 million. In accordance with the Commission's order in Docket No. 23-48-EL, if the Company's spending exceeds the consolidated budget cap by more than 2.5%, the Company's revenue requirement will be reduced in that Fiscal Year's reconciliation filing by an amount equal to the calculated revenue requirement associated with the overspend. The entire amount of overspend that exceeds the original soft budget cap will be treated as if that amount was being put into service in the fiscal year. A revenue requirement will be calculated on the entire overspend above the soft budget cap, ignoring the half-year convention. The Company has calculated the full year revenue requirement adjustment on Attachment JDO-2, and it is reflected as a reduction to the FY 2025 actual Revenue Requirement of $937,813 as shown on Attachment JDO-1, Page 1, Line 25.

Q. Does the FY 2025 revenue requirement reflect the removal of DG projects as ordered in the FY 2024 reconciliation?

A. Yes. In the FY 2024 reconciliation in Docket No. 22-53-EL, the actual FY 2024 revenue requirement reflected the removal of DG projects in vintage years FY 2018 through FY 2024, including the impact on the revenue requirement for FY 2018 through FY 2024. However, the FY 2025 revenue requirement had already been approved and therefore, the impact on the FY 2025 revenue requirement had not yet been reflected. Therefore, the FY 2025 revenue requirement on Attachment JDO-1, Page 1, Lines 5 through 11, column (c) reflects the FY 2025 impact of the removal of the DG projects for vintage years 2018 through 2024.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment JDO-1

Revenue Requirement Summary and Calculation
FY 2025 Electric Infrastructure, Safety, and Reliability Plan Reconciliation

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2025 (a)	Actual Fiscal Year 2025 (b)	Variance Fiscal Year 2025 (c)=(b)-(a)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$13,075,000	$13,261,370	$186,370
2	Current Year Inspection & Maintenance (I&M)	$700,000	$661,514	($38,486)
3	Current Year Other Programs	$365,000	$0	($365,000)
4	**Total O&M Expense Component of Revenue Requirement**	**$14,140,000**	**$13,922,884**	**($217,116)**
	Capital Investment:			
5	Actual 2025 Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,666,473	$1,641,489	($24,984)
6	Actual 2025 Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$3,862,929	$3,839,805	($23,123)
7	Actual 2025 Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,195,475	$5,146,758	($48,717)
8	Actual 2025 Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$8,058,008	$7,982,935	($75,074)
9	Actual 2025 Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$4,720,533	$4,722,099	$1,565
10	Actual 2025 Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base	$5,507,844	$5,509,938	$2,094
11	Actual 2025 Revenue Requirement on FY 2024 Incremental Capital included in ISR Rate Base	$6,018,242	$5,234,965	($783,276)
12	Actual 2025 Revenue Requirement on FY 2025 Incremental Capital included in ISR Rate Base	$3,601,979	$4,519,641	$917,662
13	Subtotal	$38,631,484	$38,597,630	($33,854)
14	FY 2025 Property Tax Recovery Adjustment	$4,094,385	$9,604,379	$5,509,995
15	Income Tax True-Up and Retirement Correction on FY 2024 Update	$0	($200,527)	($200,527)
16	Income Tax True-Up for FY 2023 and FY 2024 on FY 2023 Update	$0	$36,505	$36,505
17	Formula Correction to FY 2019 vintage Intangibles impacting FY 2023 and 2024 Updates (Income Tax)	$0	($61,475)	($61,475)
18	Formula Correction to FY 2018 deferred tax proration impacting FY 2024 Update (Income Tax)		($345)	($345)
19	**Total Capital Investment Component of Revenue Requirement**	**$42,725,869**	**$47,976,168**	**$5,250,299**
20	**Total Fiscal Year Revenue Requirement**	**$56,865,869**	**$61,899,052**	**$5,033,183**
21	FY 2025 Tax Hold Harmless Adjustment per Attachment NH-1	(2,003,987)	(1,961,095)	$42,892
22	FY 2024 Tax Hold Harmless Adjustment per Attachment NH-2	-	35,486	$35,486
23	FY 2023 Tax Hold Harmless Adjustment per Attachment NH-3	-	28,496	$28,496
24	Total Hold Harmless Adjustments	($2,003,987)	($1,897,113)	$106,874
25	FY 2025 Overspend Adjustment	-	(937,813)	(937,813)
26	**Total Net Revenue Requirement**	**$54,861,882**	**$59,064,126**	**$4,202,244**
27	**Incremental Fiscal Year Rate Adjustment**		**$4,202,244**	

Column/Line Notes:
Col (a) Docket No. 23-48-EL, FY 2024 Electric ISR Plan, Section 5: Attachment 1 (C), Page 1 of 38, Column (b)

Col (b)
1 Vegetation Management, Attachment EJW-1, Table 12
2 Other Operations and Maintenance, Attachment EJW-1, Table 13
3 Other Operations and Maintenance, Attachment EJW-1, Table 13
4 Sum of Lines 1 through 3
5 Page 2 of 39, Line 40 column (i)
6 Page 5 of 39, Line 42 column (h)
7 Page 10 of 39, Line 39 column (g)
8 Page 13 of 39, Line 40 column (f)
9 Page 17 of 39, Line 39 column (e)
10 Page 20 of 39, Line 39 column (d)
11 Page 23 of 39, Line 35 column (b)
12 Page 26 of 39, Line 33 column (a)
13 Sum of Lines 5 through 12
14 Page 36 of 39, Line 96, Column (aa) x 1,000
15 Page 23 of 39, Line 37 column (a) or Lines 38 thru 40 Column (a)
16 Page 20 of 39, Line 41 columns (a) thru (c)
17 Page 5 of 39, Line 44 column (f) thru (g)
18 Page 2 of 39, Line 42 column (h)
19 Sum of Lines 13 through 18
20 Line 4 + Line 19
21 Attachment NH-1, Page 1, Line 23, column (c)
22 Attachment NH-2, Page 1, Line 23, column (c)
23 Attachment NH-3, Page 1, Line 23, column (c)
24 Sum of Lines 21 through 23
25 Attachment JDO-2, Page 1, Line 33, column (c)
26 Sum of Lines 20 + 24 + 25
27 Line 26 Col (b) - Line 26 Col (a)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 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)	Fiscal Year 2025 (i)
	Capital Investment Allowance											
1	*Non-Discretionary Capital*			$1,559,020								
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256								
3	Total Allowed Capital Included in Rate Base	Page 29 of 39, Line 4(a)		$16,197,276	$0	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base											
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$16,197,276	$0	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 39 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$21,442,348	$21,442,348	$21,442,348	$21,442,348	$21,442,348	$21,442,348	$21,442,348	$21,442,348	$21,442,348
	Change in Net Capital Included in Rate Base											
7	Capital Included in Rate Base	Line 3		$16,197,276	$0	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$16,197,276	$16,197,276	$16,197,276	$16,197,276	$16,197,276	$16,197,276	$16,197,276	$16,197,276	$16,197,276
10	Cost of Removal	Page 29 of 39 , Line 7 ,Col (a)		$1,685,747	$0	$0	$0	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**	**$17,883,023**
	Deferred Tax Calculation:											
12	Composite Book Depreciation Rate		1/	3.40%	3.26%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
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 39, Line 29; then = Page 3 of 39, Column (e)		$12,937,234	$519,127	$480,151	$444,195	$410,829	$56,227	$487,528	$938,525	$868,061
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$12,937,234	$13,456,361	$13,936,512	$14,380,707	$14,791,536	$14,847,762			
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/							$487,528	$1,426,053	$2,294,114
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12	2/	$364,520	$699,021	$677,578	$677,578	$677,578	$100,244	$577,334	$677,578	$677,578
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$364,520	$1,063,540	$1,741,119	$2,418,697	$3,096,275	$3,196,519	$3,773,853	$4,451,431	$5,129,010
21	Cumulative Book / Tax Timer	Columns (a) through (f): Line 17 - Line 20, Then Line 18 - Line 20		$12,572,714	$12,392,820	$12,195,393	$11,962,010	$11,695,261	$11,651,243	($3,286,325)	($3,025,378)	($2,834,896)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (f)	3/							$3,196,519	$3,196,519	$3,196,519
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22								($89,805)	$171,141	$361,623
24	Effective Tax Rate		4/	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (f): Line 21 * Line 24, Then Line 23 * Line 24		$2,640,270	$2,602,492	$2,561,033	$2,512,022	$2,456,005	$2,446,761	($18,859)	$35,940	$75,941
26	Less: FY 2018 Federal NOL (Generation) / Utilization	Year 1 = Page 29 of 39 , Line 15 ,Col (a) ; then = Prior Year Line 26	3/	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	$0	$0	$0
27	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,326,421	$1,326,421	$1,326,421	$1,326,421	$1,326,421	$1,326,421	$1,326,421	$1,326,421	$1,326,421
28	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 27		$968,193	$930,415	$888,955	$839,945	$783,928	$774,684	$1,307,562	$1,362,361	$1,402,362
	Rate Base Calculation:											
29	Cumulative Incremental Capital Included in Rate Base	Line 11		$17,883,023	$17,883,023	$17,883,023	$17,883,023	$17,883,023	$17,883,023	$17,883,023	$17,883,023	$17,883,023
30	Accumulated Depreciation	-Line 20		($364,520)	($1,063,540)	($1,741,119)	($2,418,697)	($3,096,275)	($3,196,519)	($3,773,853)	($4,451,431)	($5,129,010)
31	Deferred Tax Reserve	-Line 28		($968,193)	($930,415)	($888,955)	($839,945)	($783,928)	($774,684)	($1,307,562)	($1,362,361)	($1,402,362)
32	Year End Rate Base before Deferred Tax Proration	Sum of Lines 29 through 31		$16,550,310	$15,889,067	$15,252,949	$14,624,381	$14,002,820	$13,911,820	$12,801,608	$12,069,231	$11,351,651
	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/	$8,275,155	$16,219,689	$15,571,008	$14,938,665	$14,313,601	$13,402,214	$13,402,214	$12,435,419	$11,710,441
34	Proration Adjustment	Page 4 of 39, Line 40				($1,780)	($2,104)	($2,404)	($1,206)	($1,206)	$2,352	$1,717
35	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$8,275,155	$16,219,689	$15,569,229	$14,936,561	$14,311,196	$13,401,008	$13,401,008	$12,437,771	$11,712,158
36	Pre-Tax ROR	Page 38 of 39, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
37	Proration	Line 14	2/						14.79%	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/	$681,045	$1,334,880	$1,281,348	$1,229,279	$1,177,811	$163,169	$939,734	$1,023,629	$963,911
39	Book Depreciation	Line 19		$364,520	$699,021	$677,578	$677,578	$677,578	$100,244	$577,334	$677,578	$677,578
40	**Annual Revenue Requirement**	Line 38 + Line 39		**$1,045,565**	**$2,033,901**	**$1,958,926**	**$1,906,857**	**$1,855,390**	**$263,414**	**$1,517,067**	**$1,701,207**	**$1,641,489**
41	Annual Revenue Requirement per Docket No. 22-53-EL FY 2024 Electric ISR Reconciliation, Page 1, Line 5(b) or Page 2, Line 40(h)										$1,701,552	
42	2024 Formula Correction										($345)	

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 2025 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 39, Line 3		$16,197,276		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%					
3	Capital Repairs Deduction	Line 1 * Line 2		$1,457,755	NG MACRS basis:	Line 22, Column (a)		$7,191,118	
4		`						Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$16,197,276	FY Mar-2018	3.750%		$269,667	$12,937,234
7	Less Capital Repairs Deduction	- Line 3		($1,457,755)	FY Mar-2019	7.219%		$519,127	$13,456,361
8	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7		$14,739,521	FY Mar-2020	6.677%		$480,151	$13,936,512
9	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2021	6.177%		$444,195	$14,380,707
10	Plant Eligible for Bonus Depreciation	Line 8 * Line 9		$14,739,521	FY Mar-2022	5.713%		$410,829	$14,791,536
11	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%	FY Mar-2023 (Apr-May 2022)	5.285%	0.782%	$56,227	$14,847,762
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)		$16,197,276	
15	Total Bonus Depreciation Rate	Line 11 + Line 12 + Line 13 + Line 14		51.21%	Cumulative Book Depreciation	- Page 2 of 39, Line 20, Col (f)		($3,196,519)	
16	Bonus Depreciation	Line 10 * Line 15		$7,548,403	PPL MACRS basis:	Line 14(e) + Line 15(e)		$13,000,757	
17									
18	Remaining Tax Depreciation				Mar-2023 (Jun-Mar 2023)	3.750%		$487,528	$487,528
19	Plant Additions	Line 1		$16,197,276	Mar 2024	7.219%		$938,525	$1,426,053
20	Less Capital Repairs Deduction	Line 3		$1,457,755	Mar 2025	6.677%		$868,061	$2,294,114
21	Less Bonus Depreciation	Line 16		$7,548,403	Mar 2026	6.177%		$803,057	$3,097,170
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 19 - Line 20 - Line 21		$7,191,118	Mar 2027	5.713%		$742,733	$3,839,903
23	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar 2028	5.285%		$687,090	$4,526,993
24	Remaining Tax Depreciation	Line 22 * Line 23		$269,667	Mar 2029	4.888%		$635,477	$5,162,470
25					Mar 2030	4.522%		$587,894	$5,750,365
26	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662	Mar 2031	4.462%		$580,094	$6,330,458
27	Cost of Removal	Page 2 of 39, Line 10		$1,685,747	Mar 2032	4.461%		$579,964	$6,910,422
28					Mar 2033	4.462%		$580,094	$7,490,516
29	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 16, 24, 26, and 27		$12,937,234	Mar 2034	4.461%		$579,964	$8,070,480
30					Mar 2035	4.462%		$580,094	$8,650,573
31					Mar 2036	4.461%		$579,964	$9,230,537
32					Mar 2037	4.462%		$580,094	$9,810,631
33					Mar 2038	4.461%		$579,964	$10,390,595
34					Mar 2039	4.462%		$580,094	$10,970,689
35					Mar 2040	4.461%		$579,964	$11,550,652
36					Mar 2041	4.462%		$580,094	$12,130,746
37					Mar 2042	4.461%		$579,964	$12,710,710
38					Mar 2043	2.231%		$290,047	$13,000,757
39						92.78%		$13,000,757	
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 2025 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 39, Line 19. Note there are 2 columns to sum for FY23.	$677,578	$677,578	$677,578	$677,578
2	Bonus Depreciation		$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 2 of 39, Line 16. Note there are 2 columns to sum for FY23.	($410,829)	($543,755)	($938,525)	($868,061)
4	FY18 tax (gain)/loss on retirements		$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$266,750	$133,823	($260,946)	($190,482)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$56,017	$28,103	($54,799)	($40,001)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction					
9	Cost of Removal					
10	Cumulative Book / Tax Timer	Line 8 + Line 9	$0	$0	$0	$0
11	Effective Tax Rate		21%	21%	21%	21%
12	Deferred Tax Reserve	Line 10 × Line 11	$0	$0	$0	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12	$56,017	$28,103	($54,799)	($40,001)
14	Net Operating Loss		$0	$0	$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	$56,017	$28,103	($54,799)	($40,001)
	Allocation of FY 2018 Estimated Federal NOL					
16	Cumulative Book/Tax Timer Subject to Proration	Line 5	$266,750	$133,823	($260,946)	($190,482)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	$0	$0	$0	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	$266,750	$133,823	($260,946)	($190,482)
19	Total FY 2018 Federal NOL		$0	$0	$0	$0
20	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 17 ÷ Line 18) × Line 19	$0	$0	$0	$0
21	Allocated FY 2018 Federal NOL Subject to Proration	(Line 16 ÷ Line 18) × Line 19	$0	$0	$0	$0
22	Effective Tax Rate		21%	21%	21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 × Line 22	$0	$0	$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	$56,017	$28,103	($54,799)	($40,001)

		(e)	(f)	(g)	(h)	(i)	(j)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23	FY24	FY25
25	April	30	91.78%	$4,284	$2,149	($4,191)	($3,059)
26	May	31	83.29%	$3,888	$1,951	($3,803)	($2,776)
27	June	30	75.07%	$3,504	$1,758	($3,428)	($2,502)
28	July	31	66.58%	$3,108	$1,559	($3,040)	($2,219)
29	August	31	58.08%	$2,711	$1,360	($2,652)	($1,936)
30	September	30	49.86%	$2,328	$1,168	($2,277)	($1,662)
31	October	31	41.37%	$1,931	$969	($1,889)	($1,379)
32	November	30	33.15%	$1,548	$776	($1,514)	($1,105)
33	December	31	24.66%	$1,151	$577	($1,126)	($822)
34	January	31	16.16%	$755	$379	($738)	($539)
35	February	28	8.49%	$396	$199	($388)	($283)
36	March	31	0.00%	$0	$0	$0	$0
37	Total	365		$25,604	$12,845	($25,047)	($18,284)
38	Deferred Tax Without Proration	Line 24		$56,017	$28,103	($54,799)	($40,001)
39	Average Deferred Tax without Proration	Line 24 * 50%		$28,009	$14,051	($27,399)	($20,001)
40	Proration Adjustment	Line 37 - Line 39		($2,404)	($1,206)	$2,352	$1,717

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 24 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 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)	Fiscal Year 2025 (h)
	Capital Investment Allowance										
1	*Non-Discretionary Capital*			$6,462,921							
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 29 of 39, Line 4(b)		$31,949,697	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base										
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)		$31,949,697	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 39 , Line 10 ,Col (b)		($10,649,479)	$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		$42,599,176	$42,599,176	$42,599,176	$42,599,176	$42,599,176	$42,599,176	$42,599,176	$42,599,176
	Change in Net Capital Included in Rate Base										
7	Capital Included in Rate Base	Line 3, Column (a)		$31,949,697	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$31,949,697	$31,949,697	$31,949,697	$31,949,697	$31,949,697	$31,949,697	$31,949,697	$31,949,697
10	Cost of Removal	Page 29 of 39 , Line 7 ,Col (b)		$245,506							
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$32,195,203**	**$32,195,203**	**$32,195,203**	**$32,195,203**	**$32,195,203**	**$32,195,203**	**$32,195,203**	**$32,195,203**
	Deferred Tax Calculation:										
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770	1/	3.26%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
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 39, Line 28 Then = Page 6 of 39 Column (e)		$9,812,806	$1,787,475	$1,653,272	$1,529,468	$209,280	$1,013,167	$1,950,413	$1,803,977
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$9,812,806	$11,600,281	$13,253,553	$14,783,021	$14,992,301			
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/						$1,013,167	$2,963,580	$4,767,556
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$694,367	$1,346,134	$1,346,134	$1,346,134	$199,154	$1,146,980	$1,346,134	$1,346,134
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$694,367	$2,040,501	$3,386,634	$4,732,768	$4,931,922	$6,078,902	$7,425,036	$8,771,170
21	Cumulative Book / Tax Timer	Columns (a) through(e): Line 17 - Line 20, Then Line 18 - Line 20		$9,118,439	$9,559,780	$9,866,918	$10,050,253	$10,060,379	($5,065,736)	($4,461,457)	($4,003,614)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (e)	3/						$4,931,922	$4,931,922	$4,931,922
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22							($133,813)	$470,466	$928,309
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (e): Line 21 * Line 24, Then Line 23 * Line 24		$1,914,872	$2,007,554	$2,072,053	$2,110,553	$2,112,680	($28,101)	$98,798	$194,945
26	Add: FY 2019 Federal NOL (Generation) / Utilization	Page 29 of 39 , Line 15 ,Col (b)	3/	$991,622	$991,622	$991,622	$991,622	$991,622	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$2,906,494	$2,999,176	$3,063,675	$3,102,175	$3,104,301	($28,101)	$98,798	$194,945
	Rate Base Calculation:										
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$32,195,203	$32,195,203	$32,195,203	$32,195,203	$32,195,203	$32,195,203	$32,195,203	$32,195,203
29	Accumulated Depreciation	-Line 20		($694,367)	($2,040,501)	($3,386,634)	($4,732,768)	($4,931,922)	($6,078,902)	($7,425,036)	($8,771,170)
30	Deferred Tax Reserve	-Line 27		($2,906,494)	($2,999,176)	($3,063,675)	($3,102,175)	($3,104,301)	$28,101	($98,798)	($194,945)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$28,594,342	$27,155,527	$25,744,894	$24,360,260	$24,158,979	$26,144,402	$24,671,369	$23,229,088
	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/	$14,297,171	$27,874,935	$26,450,210	$25,052,577	$25,252,331	$25,252,331	$25,407,885	$23,950,228
33	Proration Adjustment	Page 7 of 39, Line 42		$0	$0	$0	($492)	($944)	($944)	$7,161	$1,727
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$14,297,171	$27,874,935	$26,450,210	$25,052,085	$25,251,386	$25,251,386	$25,415,046	$23,951,955
35	Pre-Tax ROR	Page 38 of 39, Line 35		8.23%	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/	$1,176,657	$2,294,107	$2,176,852	$2,061,787	$307,458	$1,770,731	$2,091,658	$1,971,246
38	Book Depreciation	Line 19		$694,367	$1,346,134	$1,346,134	$1,346,134	$199,154	$1,146,980	$1,346,134	$1,346,134
39	Annual Revenue Requirement	Line 37 + Line 38		$1,871,024	$3,640,241	$3,522,986	$3,407,921	$506,612	$2,917,711	$3,437,792	$3,317,380
40	Revenue Requirement of Plant	Year 1 = Line 39*7/12, Then = Line 39		$1,091,431	$3,640,241	$3,522,986	$3,407,921	$506,612	$2,917,711	$3,437,792	$3,317,380
41	Revenue Requirement of Intangible	Page 8 of 39, Line 36, Column (l) ~ (aa)		$434,302	$705,779	$655,914	$617,127	$81,808	$520,069	$562,455	$522,426
42	**Revenue Requirement**	Line 40 + Line 41		**$1,525,733**	**$4,346,020**	**$4,178,901**	**$4,025,047**	**$588,421**	**$3,437,780**	**$4,000,247**	**$3,839,805**
43	Annual Revenue Requirement per Docket No. 22-53-EL FY 2024 Electric ISR Reconciliation, Page 5, Line 42(f) and Page 1, Line 6(b) or Page 5, Line 42(g)								$3,466,062	$4,033,440	
44	2023 and 2024 Tax True-Up								($28,282)	($33,193)	

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

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

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

4/ Columns (e) 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 2025 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 39, Line 3		$31,949,697		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.68%					
3	Capital Repairs Deduction	Line 1 * Line 2		$3,092,755	MACRS basis:	Line 22, Column (a)		$24,760,699	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$31,949,697	FY Mar-2019	3.750%		$928,526	$9,812,806
7	Plant Additions			$0	FY Mar-2020	7.219%		$1,787,475	$11,600,281
8	Less Capital Repairs Deduction	Line 3		$3,092,755	FY Mar-2021	6.677%		$1,653,272	$13,253,553
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$28,856,942	FY Mar-2022	6.177%		$1,529,468	$14,783,021
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2023 (Apr-May 2022)	5.713%	0.85%	$209,280	$14,992,301
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$28,856,942					
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)		$31,949,697	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		14.20%	Cumulative Book Depreciation	- Page 5 of 39, Line 20, Col (e)		($4,931,922)	
15	Bonus Depreciation	Line 11 * Line 14		$4,096,243	PPL MACRS basis:	Line 13(e) + Line 14(e)		$27,017,774	
16									
17	Remaining Tax Depreciation				FY Mar-2023 (Jun-Mar 2023)	3.750%		$1,013,167	$1,013,167
18	Plant Additions	Line 1		$31,949,697	Mar-2024	7.219%		$1,950,413	$2,963,580
19	Less Capital Repairs Deduction	Line 3		$3,092,755	Mar-2025	6.677%		$1,803,977	$4,767,556
20	Less Bonus Depreciation	Line 15		$4,096,243	Mar-2026	6.177%		$1,668,888	$6,436,444
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$24,760,699	Mar-2027	5.713%		$1,543,525	$7,979,970
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2028	5.285%		$1,427,889	$9,407,859
23	Remaining Tax Depreciation	Line 21 * Line 22		$928,526	Mar-2029	4.888%		$1,320,629	$10,728,488
24					Mar-2030	4.522%		$1,221,744	$11,950,232
25	FY19 (Gain)/Loss incurred due to retirements	Per Tax Department	3/	$1,449,776	Mar-2031	4.462%		$1,205,533	$13,155,765
26	Cost of Removal	Page 5 of 39, Line 10		$245,506	Mar-2032	4.461%		$1,205,263	$14,361,028
27					Mar-2033	4.462%		$1,205,533	$15,566,561
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$9,812,806	Mar-2034	4.461%		$1,205,263	$16,771,824
29					Mar-2035	4.462%		$1,205,533	$17,977,357
30					Mar-2036	4.461%		$1,205,263	$19,182,620
31					Mar-2037	4.462%		$1,205,533	$20,388,153
32					Mar-2038	4.461%		$1,205,263	$21,593,416
33					Mar-2039	4.462%		$1,205,533	$22,798,949
34					Mar-2040	4.461%		$1,205,263	$24,004,212
35					Mar-2041	4.462%		$1,205,533	$25,209,745
36					Mar-2042	4.461%		$1,205,263	$26,415,008
37					Mar-2043	2.231%		$602,767	$27,017,774
38						100.000%		$27,017,774	
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 2025 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 39, Line 19. Note there are 2 columns to sum for FY23.	$1,346,134	$1,346,134	$1,346,134	$1,346,134
2	Book Depreciation - Intangibles	See the corresponding Fiscal Year on Page 8 of 39, Line 23 - Line 22. 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 39, Line 16. Note there are 2 columns to sum for FY23.	($1,529,468)	($1,222,447)	($1,950,413)	($1,803,977)
5	Remaining MACRS Tax Depreciation - Intangibles	See the corresponding Fiscal Year on Page 8 of 39, Line 19 - 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	$54,608	$104,765	($794,454)	($191,548)
8	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
9	Deferred Tax Reserve	Line 7 * Line 8	$11,468	$22,001	($166,835)	($40,225)
	Deferred Tax Not Subject to Proration					
10	Capital Repairs Deduction					
11	Cost of Removal					
12	Cumulative Book / Tax Timer	Line 10 + Line 11	$0	$0	$0	$0
13	Effective Tax Rate		21%	21%	21%	21%
14	Deferred Tax Reserve	Line 12 × Line 13	$0	$0	$0	$0
15	Total Deferred Tax Reserve	Line 9 + Line 14	$11,468	$22,001	($166,835)	($40,225)
16	Net Operating Loss		$0	$0	$0	$0
17	Net Deferred Tax Reserve	Line 15 + Line 16	$11,468	$22,001	($166,835)	($40,225)
	Allocation of FY 2019 Estimated Federal NOL					
18	Cumulative Book/Tax Timer Subject to Proration	Line 7	$54,608	$104,765	($794,454)	($191,548)
19	Cumulative Book/Tax Timer Not Subject to Proration	Line 12	$0	$0	$0	$0
20	Total Cumulative Book/Tax Timer	Line 18 + Line 19	$54,608	$104,765	($794,454)	($191,548)
21	Total FY 2019 Federal NOL		$0	$0	$0	$0
22	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 19 ÷ Line 20) × Line 21	$0	$0	$0	$0
23	Allocated FY 2019 Federal NOL Subject to Proration	(Line 18 ÷ Line 20) × Line 21	$0	$0	$0	$0
24	Effective Tax Rate		21%	21%	21%	21%
25	Deferred Tax Benefit subject to proration	Line 23 × Line 24	$0	$0	$0	$0
26	Net Deferred Tax Reserve subject to proration	Line 9 + Line 25	$11,468	$22,001	($166,835)	($40,225)

Line No.	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(g) FY22	(h) FY23	(i) FY24	(j) FY25
27	April	30	91.78%	$877	$1,683	($12,760)	($3,077)
28	May	31	83.29%	$796	$1,527	($11,579)	($2,792)
29	June	30	75.07%	$717	$1,376	($10,437)	($2,516)
30	July	31	66.58%	$636	$1,221	($9,256)	($2,232)
31	August	31	58.08%	$555	$1,065	($8,075)	($1,947)
32	September	30	49.86%	$477	$914	($6,932)	($1,671)
33	October	31	41.37%	$395	$758	($5,752)	($1,387)
34	November	30	33.15%	$317	$608	($4,609)	($1,111)
35	December	31	24.66%	$236	$452	($3,428)	($827)
36	January	31	16.16%	$154	$296	($2,247)	($542)
37	February	28	8.49%	$81	$156	($1,181)	($285)
38	March	31	0.00%	$0	$0	$0	$0
39	Total	365		$5,242	$10,056	($76,257)	($18,386)
40	Deferred Tax Without Proration	Line 26		$11,468	$22,001	($166,835)	($40,225)
41	Average Deferred Tax without Proration	Line 39 * 50%		$5,734	$11,000	($83,418)	($20,113)
42	Proration Adjustment	Line 39 - Line 41		($492)	($944)	$7,161	$1,727

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 26 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 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) NG	FY Mar-2023 (Jun 2022 -Mar 2023) (r) = (p) + (q) PPL	FY 24 Total (u) = (s) + (t) PPL	FY 25 Total (x) = (v) + (w) PPL
	Capital Investment									
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 39								
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	Beginning Acc. Tax Balance Adjustment for Step-up in Tax Basis	Line 21, Column (o)						$1,920,581	$1,920,581	$1,920,581
19	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
20	Ending Acc. Tax Balance Adjustment for Step-up in Tax Basis	Line 21, Column (o)						$1,920,581	$1,920,581	$1,920,581
21	Average Acc. Tax Balance	(Line 17 + Line 19) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410	$3,460,626	$2,177,230	$2,776,153	$3,232,468
22	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
23	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
24	Average Acc. Dep. Balance	(Line 22 + Line 23) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719	$1,887,244	$2,134,432	$2,595,470	$3,089,845
25	Number of days									
26	Proration Percentage									
27	Average Book / Tax Timer	Line 21 - Line 24	$926,838	$1,304,582	$1,835,590	$1,725,691	$232,774	$36,466	$180,683	$142,624
28	Effective Tax Rate									
29	Deferred Tax Reserve	Line 27 × Line 28	$194,636	$273,962	$385,474	$362,395	$48,883	$7,658	$37,944	$29,951
	Rate Base Calculation:									
30	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
31	Deferred Tax Reserve	Line 29	$194,636	$273,962	$385,474	$362,395	$48,883	$7,658	$37,944	$29,951
32	Average Rate Base	Line 30 - Line 31	$3,039,402	$2,568,695	$1,962,808	$1,491,512	$183,892	$1,122,333	$827,213	$340,830
	Revenue Requirement Calculation:									
33	Pre-Tax ROR	year 1 = Page 38 of 39, Line 27, column (e)×7÷12 Then = Page 38 of 39, Line 27(e)								
34	Return and Taxes	Line 32 × Line 33	$145,917	$211,404	$161,539	$122,751	$15,134	$92,368	$68,080	$28,050
35	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375	$66,674	$427,701	$494,375	$494,375
36	Annual Revenue Requirement	Line 34 + Line 35	$434,302	$705,779	$655,914	$617,127	$81,808	$520,069	$562,455	$522,426

The Narragansett Electric Company
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FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
MACRS Tables For Information Systems

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

The Narragansett Electric Company
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FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 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)	Fiscal Year 2025 (g)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*			$27,406,375						
	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 29 of 39, Line 4(c)		$67,003,710	$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		$67,003,710	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 39 , Line 10 ,Col (c)		$4,015,632	$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		$62,988,078	$62,988,078	$62,988,078	$62,988,078	$62,988,078	$62,988,078	$62,988,078
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3		$67,003,710	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 33 of 39, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$37,891,340	$37,891,340	$37,891,340	$37,891,340	$37,891,340	$37,891,340	$37,891,340
10	Cost of Removal	Page 29 of 39 , Line 7 ,Col (c)		$11,264,831						
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$49,156,170**	**$49,156,170**	**$49,156,170**	**$49,156,170**	**$49,156,170**	**$49,156,170**	**$49,156,170**
	Deferred Tax Calculation:									
12	Composite Book Depreciation Rate	Page 31 of 39, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/				54	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 39, Line 28, Then = Page 11 of 39, Column (e)		$23,371,948	$4,278,204	$3,956,998	$541,580	$2,314,994	$4,456,518	$4,121,924
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$23,371,948	$27,650,152	$31,607,149	$32,148,729			
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/					$2,314,994	$6,771,512	$10,893,437
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$995,212	$1,990,423	$1,990,423	$294,474	$1,695,950	$1,990,423	$1,990,423
20	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$995,212	$2,985,635	$4,976,058	$5,270,532	$6,966,481	$8,956,905	$10,947,328
21	Cumulative Book / Tax Timer	Columns (c) & (d): Line 17 - Line 20, Then Line 18 - Line 20		$22,376,736	$24,664,517	$26,631,091	$26,878,198	($4,651,487)	($2,185,392)	($53,891)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (d)	3/					$5,270,532	$5,270,532	$5,270,532
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22						$619,044	$3,085,139	$5,216,640
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (c) & (d): Line 21 * Line 24, Then Line 23 * Line 24		$4,699,115	$5,179,548	$5,592,529	$5,644,422	$129,999	$647,879	$1,095,494
26	Add: FY 2020 Federal NOL (Generation) / Utilization	Page 29 of 39, Line 15, Col (c)	3/	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$3,236,134	$3,716,568	$4,129,549	$4,181,441	$129,999	$647,879	$1,095,494
	Rate Base Calculation:									
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$49,156,170	$49,156,170	$49,156,170	$49,156,170	$49,156,170	$49,156,170	$49,156,170
29	Accumulated Depreciation	-Line 20		($995,212)	($2,985,635)	($4,976,058)	($5,270,532)	($6,966,481)	($8,956,905)	($10,947,328)
30	Deferred Tax Reserve	-Line 27		($3,236,134)	($3,716,568)	($4,129,549)	($4,181,441)	($129,999)	($647,879)	($1,095,494)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$44,924,825	$42,453,967	$40,050,563	$39,704,197	$42,059,689	$39,551,386	$37,113,348
	Revenue Requirement Calculation:									
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 * Page 16 of 39, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$16,364,035	$43,689,396	$41,252,265	$41,055,126	$41,055,126	$40,805,538	$38,332,367
33	Proration Adjustment	Page 12 of 39, Line 40		$30,912	$18,700	$17,726	$7,807	$7,807	$22,229	$19,213
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$16,394,947	$43,708,096	$41,269,991	$41,062,934	$41,062,934	$40,827,767	$38,351,580
35	Pre-Tax ROR	Page 38 of 39, Line 35		8.23%	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/	$1,349,304	$3,597,176	$3,396,520	$499,978	$2,879,502	$3,360,125	$3,156,335
38	Book Depreciation	Line 19		$995,212	$1,990,423	$1,990,423	$294,474	$1,695,950	$1,990,423	$1,990,423
39	**Annual Revenue Requirement**	Line 37 + Line 38		**$2,344,516**	**$5,587,600**	**$5,386,944**	**$794,451**	**$4,575,451**	**$5,350,548**	**$5,146,758**
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 31 of 39, 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 2025 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 39, Line 3		$67,003,710	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%					
3	Capital Repairs Deduction	Line 1 * Line 2		$5,702,016	NG MACRS basis:	Line 22, Column (a)		$59,263,106	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Proration	MACRS	Tax Depr
6	Plant Additions	Line 1		$67,003,710	FY Mar-2020	3.750%		$2,222,366	$23,371,948
7	Plant Additions			$0	FY Mar-2021	7.219%		$4,278,204	$27,650,151
8	Less Capital Repairs Deduction	Line 3		$5,702,016	FY Mar-2022	6.677%		$3,956,998	$31,607,149
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$61,301,694	FY Mar-2023 (Apr-May 2022)	6.177%	0.914%	$541,580	$32,148,729
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%					
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$61,301,694	PPL Acquisition - May 25, 2022				
12	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%	Book Cost	Line 1, Column (a)		$67,003,710	
13	Bonus Depreciation Rate	1 * 0% * 25%		0.00%	Cumulative Book Depreciation	- Page 10 of 39, Line 20, Col (d)		($5,270,532)	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		3.33%	PPL MACRS basis:	Line 12(e) + Line 13(e)		$61,733,178	
15	Bonus Depreciation	Line 11 * Line 14		$2,038,588					
16					FY Mar-2023 (Jun-Mar 2023)	3.750%		$2,314,994	$2,314,994
17	Remaining Tax Depreciation				Mar-2024	7.219%		$4,456,518	$6,771,512
18	Plant Additions	Line 1		$67,003,710	Mar-2025	6.677%		$4,121,924	$10,893,437
19	Less Capital Repairs Deduction	Line 3		$5,702,016	Mar-2026	6.177%		$3,813,258	$14,706,695
20	Less Bonus Depreciation	Line 15		$2,038,588	Mar-2027	5.713%		$3,526,816	$18,233,512
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$59,263,106	Mar-2028	5.285%		$3,262,598	$21,496,110
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2029	4.888%		$3,017,518	$24,513,628
23	Remaining Tax Depreciation	Line 21 * Line 22		$2,222,366	Mar-2030	4.522%		$2,791,574	$27,305,202
24					Mar-2031	4.462%		$2,754,534	$30,059,736
25	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147	Mar-2032	4.461%		$2,753,917	$32,813,654
26	Cost of Removal	Page 10 of 39, Line 10		$11,264,831	Mar-2033	4.462%		$2,754,534	$35,568,188
27					Mar-2034	4.461%		$2,753,917	$38,322,105
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$23,371,948	Mar-2035	4.462%		$2,754,534	$41,076,639
29					Mar-2036	4.461%		$2,753,917	$43,830,557
30					Mar-2037	4.462%		$2,754,534	$46,585,091
31					Mar-2038	4.461%		$2,753,917	$49,339,008
32					Mar-2039	4.462%		$2,754,534	$52,093,542
33					Mar-2040	4.461%		$2,753,917	$54,847,459
34					Mar-2041	4.462%		$2,754,534	$57,601,994
35					Mar-2042	4.461%		$2,753,917	$60,355,911
36					Mar-2043	2.231%		$1,377,267	$61,733,178
37						100.000%		$61,733,178	
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 2025 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 39, Line 19. Note there are 2 columns to sum for FY23.		$1,990,423	$1,990,423	$1,990,423	$1,990,423
2	Bonus Depreciation			$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 10 of 39, Line 16. Note there are 2 columns to sum for FY23.		($3,956,998)	($2,856,575)	($4,456,518)	($4,121,924)
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		($1,966,574)	($866,151)	($2,466,095)	($2,131,501)
6	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($412,981)	($181,892)	($517,880)	($447,615)
	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	Cumulative Book / Tax Timer	Line 8 + Line 9		$0	$0	$0	$0
11	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
12	Deferred Tax Reserve	Line 10 * Line 11		$0	$0	$0	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12		($412,981)	($181,892)	($517,880)	($447,615)
14	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		$0	$0	$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14		($412,981)	($181,892)	($517,880)	($447,615)
	Allocation of FY 2020 Estimated Federal NOL						
16	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5		($1,966,574)	($866,151)	($2,466,095)	($2,131,501)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10		$0	$0	$0	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17		($1,966,574)	($866,151)	($2,466,095)	($2,131,501)
19	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		$0	$0	$0	$0
20	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19		$0	$0	$0	$0
21	Allocated FY 2020 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19		$0	$0	$0	$0
22	Effective Tax Rate			21%	21%	21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22		$0	$0	$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23		($412,981)	($181,892)	($517,880)	($447,615)
		(e)	(f)	(g)	(h)	(i)	(j)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23	FY24	FY25
25	April	30	91.78%	($31,586)	($13,912)	($39,610)	($34,235)
26	May	31	83.29%	($28,663)	($12,624)	($35,944)	($31,067)
27	June	30	75.07%	($25,835)	($11,379)	($32,397)	($28,002)
28	July	31	66.58%	($22,912)	($10,091)	($28,732)	($24,833)
29	August	31	58.08%	($19,989)	($8,804)	($25,066)	($21,665)
30	September	30	49.86%	($17,160)	($7,558)	($21,519)	($18,600)
31	October	31	41.37%	($14,237)	($6,271)	($17,854)	($15,431)
32	November	30	33.15%	($11,409)	($5,025)	($14,307)	($12,366)
33	December	31	24.66%	($8,486)	($3,738)	($10,641)	($9,198)
34	January	31	16.16%	($5,563)	($2,450)	($6,976)	($6,030)
35	February	28	8.49%	($2,923)	($1,287)	($3,665)	($3,168)
36	March	31	0.00%	$0	$0	$0	$0
37	Total	365		($188,764)	($83,139)	($236,711)	($204,595)
38	Deferred Tax Without Proration	Line 24		($412,981)	($181,892)	($517,880)	($447,615)
39	Average Deferred Tax without Proration	Year 1=Line 38 * Page 16 of 39, Line 16, Col (e); then = Line 38 * 50%		($206,490)	($90,946)	($258,940)	($223,808)
40	Proration Adjustment	Line 37 - Line 39		$17,726	$7,807	$22,229	$19,213

Column Notes:

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

(g) through (j) Current Year Line 24 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 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)	Fiscal Year 2025 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*			$34,595,920					
2	*Discretionary Capital* 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 29 of 39, Line 4(d)		$114,637,174	$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		$114,637,174	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 39 , Line 10 ,Col (d)		$21,996,026	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$92,641,148	$92,641,148	$92,641,148	$92,641,148	$92,641,148	$92,641,148
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$114,637,174	$0	$0	$0	$0	$0
8	Depreciation Expense	Page 33 of 39, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$64,730,253	$64,730,253	$64,730,253	$64,730,253	$64,730,253	$64,730,253
10	Cost of Removal	Page 29 of 39 , Line 7 ,Col (d)		$10,220,721					
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$74,950,974**	**$74,950,974**	**$74,950,974**	**$74,950,974**	**$74,950,974**	**$74,950,974**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 31 of 39, 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 14 of 39, Line 28, Column (a), Then = Line Page 14 of 39 , Column (e)		$43,972,493	$6,332,113	$866,471	$4,117,983	$7,927,392	$7,332,206
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$43,972,493	$50,304,606	$51,171,077			
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/				$4,117,983	$12,045,375	$19,377,581
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line		$1,463,730	$2,927,460	$433,104	$2,494,357	$2,927,460	$2,927,460
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$1,463,730	$4,391,190	$4,824,294	$7,318,651	$10,246,111	$13,173,571
21	Cumulative Book / Tax Timer	Columns (a) through (c): Line 17 - Line 20, Then Line 18 - Line 20		$42,508,763	$45,913,416	$46,346,783	($3,200,668)	$1,799,264	$6,204,010
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (c)	3/				$4,824,294	$4,824,294	$4,824,294
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$1,623,626	$6,623,558	$11,028,304
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (c): Line 21 * Line 24, Then Line 23 * Line 24		$8,926,840	$9,641,817	$9,732,824	$340,962	$1,390,947	$2,315,944
26	Add: FY 2021 Federal NOL (Generation) / Utilization	Page 29 of 39, Line 15, Col (d)	3/	($5,639,147)	($5,639,147)	($5,639,147)	$0	$0	$0
27	Net Deferred Tax Reserve beforee Proration Adjustment	Sum of Lines 25 through 26		$3,287,693	$4,002,670	$4,093,677	$340,962	$1,390,947	$2,315,944
	Rate Base Calculation:								
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$74,950,974	$74,950,974	$74,950,974	$74,950,974	$74,950,974	$74,950,974
29	Accumulated Depreciation	-Line 20		($1,463,730)	($4,391,190)	($4,824,294)	($7,318,651)	($10,246,111)	($13,173,571)
30	Deferred Tax Reserve	-Line 27		($3,287,693)	($4,002,670)	($4,093,677)	($340,962)	($1,390,947)	($2,315,944)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$70,199,551	$66,557,114	$66,033,003	$67,291,362	$63,313,916	$59,461,459
	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/	$35,099,776	$68,378,333	$66,924,238	$66,924,238	$65,302,639	$61,387,688
33	Proration Adjustment	Page 15 of 39, Line 40		$16,455	$30,689	$18,541	$18,541	$45,068	$39,703
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$35,116,231	$68,409,021	$66,942,779	$66,942,779	$65,347,707	$61,427,391
35	Pre-Tax ROR	Page 38 of 39, 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),(b) and (e): L 34 * L 35; Cols (c) and (d): L 34 * L 35 * L 36	2/	$2,890,066	$5,630,062	$815,088	$4,694,303	$5,378,116	$5,055,474
38	Book Depreciation	Line 19		$1,463,730	$2,927,460	$433,104	$2,494,357	$2,927,460	$2,927,460
39	Revenue Requirement of Intangible Assets								
40	**Annual Revenue Requirement**	**Line 37 + Line 38 + Line 39**		**$4,353,796**	**$8,557,523**	**$1,248,192**	**$7,188,659**	**$8,305,577**	**$7,982,935**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 39, 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.
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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 2025 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 39, Line 3(a)		$114,637,174		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%					
3	Capital Repairs Deduction	Line 1 * Line 2		$26,922,627	MACRS basis:	Line 21, Column (a)		$87,714,547	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$114,637,174	FY Mar-2021	3.750%		$3,289,296	$43,972,493
7	Plant Additions			$0	FY Mar-2022	7.219%		$6,332,113	$50,304,606
8	Less Capital Repairs Deduction	Line 3		$26,922,627	FY Mar-2023 (Apr-May 2022)	6.677%	0.988%	$866,471	$51,171,077
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$87,714,547					
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)		$114,637,174	
12	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%	Cumulative Book Depreciation	- Page 13 of 39, Line 20, Col (c)		($4,824,294)	
13	Bonus Depreciation Rate	1 * 25% * 0%		0.00%	PPL MACRS basis:	Line 11(e) + Line 12(e)		$109,812,880	
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%		$4,117,983	$4,117,983
16					Mar-2024	7.219%		$7,927,392	$12,045,375
17	Remaining Tax Depreciation				Mar-2025	6.677%		$7,332,206	$19,377,581
18	Plant Additions	Line 1		$114,637,174	Mar-2026	6.177%		$6,783,142	$26,160,722
19	Less Capital Repairs Deduction	Line 3		$26,922,627	Mar-2027	5.713%		$6,273,610	$32,434,332
20	Less Bonus Depreciation	Line 15		$0	Mar-2028	5.285%		$5,803,611	$38,237,943
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$87,714,547	Mar-2029	4.888%		$5,367,654	$43,605,596
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2030	4.522%		$4,965,738	$48,571,335
23	Remaining Tax Depreciation	Line 21 * Line 22		$3,289,296	Mar-2031	4.462%		$4,899,851	$53,471,186
24					Mar-2032	4.461%		$4,898,753	$58,369,938
25	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$3,539,849	Mar-2033	4.462%		$4,899,851	$63,269,789
26	Cost of Removal	Page 13 of 39, Line 10		$10,220,721	Mar-2034	4.461%		$4,898,753	$68,168,541
27					Mar-2035	4.462%		$4,899,851	$73,068,392
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$43,972,493	Mar-2036	4.461%		$4,898,753	$77,967,145
29					Mar-2037	4.462%		$4,899,851	$82,866,995
30					Mar-2038	4.461%		$4,898,753	$87,765,748
31					Mar-2039	4.462%		$4,899,851	$92,665,599
32					Mar-2040	4.461%		$4,898,753	$97,564,351
33					Mar-2041	4.462%		$4,899,851	$102,464,202
34					Mar-2042	4.461%		$4,898,753	$107,362,954
35					Mar-2043	2.231%		$2,449,925	$109,812,880
36						100.00%		$109,812,880	
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 2025 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 39, Line 19. Note there are 2 columns to sum for FY23.	$2,927,460	$2,927,460	$2,927,460	$2,927,460
2	Bonus Depreciation	Page 14 of 39, Line 20	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	See the corresponding Fiscal Year on Page 13 of 39, Line 16. Note there are 2 columns to sum for FY23.	($6,332,113)	($4,984,454)	($7,927,392)	($7,332,206)
4	FY 2021 tax (gain)/loss on retirements	- Page 14 of 39, Line 25				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,404,653)	($2,056,993)	($4,999,932)	($4,404,746)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($714,977)	($431,969)	($1,049,986)	($924,997)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 14 of 39, Line 3				
9	Cost of Removal	- Page 14 of 39, Line 26				
10	Cumulative Book / Tax Timer	Line 8 + Line 9	$0	$0	$0	$0
11	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
12	Deferred Tax Reserve	Line 10 * Line 11	$0	$0	$0	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12	($714,977)	($431,969)	($1,049,986)	($924,997)
14	Net Operating Loss	Page 13 of 39, Line 26	$0	$0	$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	($714,977)	($431,969)	($1,049,986)	($924,997)
	Allocation of FY 2021 Estimated Federal NOL					
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,404,653)	($2,056,993)	($4,999,932)	($4,404,746)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	$0	$0	$0	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	($3,404,653)	($2,056,993)	($4,999,932)	($4,404,746)
19	Total FY 2021 Federal NOL (Utilization)	- Page 13 of 39, Line 26 / 21%	$0	$0	$0	$0
20	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19	$0	$0	$0	$0
21	Allocated FY 2021 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19	$0	$0	$0	$0
22	Effective Tax Rate		21%	21%	21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22	$0	$0	$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	($714,977)	($431,969)	($1,049,986)	($924,997)

		(e)	(f)	(g)	(h)	(i)	(j)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23	FY24	FY25
25	April	30	91.78%	($54,684)	($33,039)	($80,307)	($70,747)
26	May	31	83.29%	($49,624)	($29,981)	($72,876)	($64,201)
27	June	30	75.07%	($44,727)	($27,023)	($65,684)	($57,865)
28	July	31	66.58%	($39,667)	($23,965)	($58,253)	($51,318)
29	August	31	58.08%	($34,606)	($20,908)	($50,821)	($44,772)
30	September	30	49.86%	($29,709)	($17,949)	($43,630)	($38,436)
31	October	31	41.37%	($24,649)	($14,892)	($36,198)	($31,889)
32	November	30	33.15%	($19,752)	($11,933)	($29,006)	($25,554)
33	December	31	24.66%	($14,691)	($8,876)	($21,575)	($19,007)
34	January	31	16.16%	($9,631)	($5,819)	($14,144)	($12,460)
35	February	28	8.49%	($5,060)	($3,057)	($7,431)	($6,547)
36	March	31	0.00%	$0	$0	$0	$0
37	Total	365		($326,800)	($197,443)	($479,925)	($422,795)
38	Deferred Tax Without Proration	Line 24		($714,977)	($431,969)	($1,049,986)	($924,997)
39	Average Deferred Tax without Proration	Line 38 × 0.5		($357,489)	($215,984)	($524,993)	($462,498)
40	Proration Adjustment	Line 37 - Line 39		$30,689	$18,541	$45,068	$39,703

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 24 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
ISR Additions April 2020 through March 2021

Line No.	Month No.	Month	FY 2021 Plant Additions (a)	In Rates (b)	Not In Rates (c) = (a) - (b)	Weight for Days (d)	Weighted Average (e) = (d) * (c)	Weight for Not in Rates (f)=(c)/Total(c)
1								
2	1	Apr-20	8,182,358	6,236,917	1,945,441	0.958	1,864,381	2.90%
3	2	May-20	8,182,358	6,236,917	1,945,441	0.875	1,702,261	2.90%
4	3	Jun-20	8,182,358	6,236,917	1,945,441	0.792	1,540,141	2.90%
5	4	Jul-20	8,182,358	6,236,917	1,945,441	0.708	1,378,021	2.90%
6	5	Aug-20	8,182,358	6,236,917	1,945,441	0.625	1,215,901	2.90%
7	6	Sep-20	8,182,358	-	8,182,358	0.542	4,432,110	12.21%
8	7	Oct-20	8,182,358	-	8,182,358	0.458	3,750,247	12.21%
9	8	Nov-20	8,182,358	-	8,182,358	0.375	3,068,384	12.21%
10	9	Dec-20	8,182,358	-	8,182,358	0.292	2,386,521	12.21%
11	10	Jan-21	8,182,358	-	8,182,358	0.208	1,704,658	12.21%
12	11	Feb-21	8,182,358	-	8,182,358	0.125	1,022,795	12.21%
13	12	Mar-21	8,182,358	-	8,182,358	0.042	340,932	12.21%
14		Total	$98,188,293	$31,184,583	$67,003,710		$24,406,351	100.00%
15	**Total September 2020 through March 2021**				**$ 57,276,504**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**						**36.43%**	

Column (a)=Page 29 of 39, Line 1(c)
Column(b)=Page 29 of 39, 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 Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 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)	Fiscal Year 2025 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*	Docket 5098, P 29 of 29. Line 1(a)		$44,269,338				
	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 29 of 39, Line 4(e)		$86,469,768	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$86,469,768	$0	$0	$0	$0
5	Retirements	Page 29 of 39 , Line 10 ,Col (e)		$34,853,004	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$51,616,764	$51,616,764	$51,616,764	$51,616,764	$51,616,764
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$86,469,768	$0	$0	$0	$0
8	Depreciation Expense	Page 33 of 39, Line 62, Col (d)		$49,906,920	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$36,562,848	$36,562,848	$36,562,848	$36,562,848	$36,562,848
10	Cost of Removal	Page 29 of 39 , Line 7 ,Col (e)		$7,612,192	$0	$0	$0	$0
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$44,175,039**	**$44,175,039**	**$44,175,039**	**$44,175,039**	**$44,175,039**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	Page 31 of 39, 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 18 of 39, Line 27, Column (a), Then = Line Page 18 of 39 , Column (e)		$41,652,259	$649,506	$3,202,984	$6,165,958	$5,703,020
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$41,652,259	$42,301,764			
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/			$3,202,984	$9,368,942	$15,071,962
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$815,545	$241,312	$1,389,778	$1,631,090	$1,631,090
20	Cumulative Book Depreciation	Prior Year Line 20 + Current Year Line 19		$815,545	$1,056,857	$2,446,635	$4,077,724	$5,708,814
21	Cumulative Book / Tax Timer	Columns (a) & (b): Line 17 - Line 20, Then Line 18 - Line 20		$40,836,714	$41,244,907	$756,350	$5,291,218	$9,363,148
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (b)	3/			$1,056,857	$1,056,857	$1,056,857
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22				$1,813,206	$6,348,075	$10,420,005
24	Effective Tax Rate			21.00%	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		$8,575,710	$8,661,431	$380,773	$1,333,096	$2,188,201
26	Add: FY 2022 Federal NOL (Generation) / Utilization	Page 29 of 39, Line 15, Col (e)	3/	($3,602,966)	($3,602,966)	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustmer	Sum of Lines 25 through 26		$4,972,744	$5,058,465	$380,773	$1,333,096	$2,188,201
	Rate Base Calculation:							
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$44,175,039	$44,175,039	$44,175,039	$44,175,039	$44,175,039
29	Accumulated Depreciation	-Line 20		($815,545)	($1,056,857)	($2,446,635)	($4,077,724)	($5,708,814)
30	Deferred Tax Reserve	-Line 27		($4,972,744)	($5,058,465)	($380,773)	($1,333,096)	($2,188,201)
31	Year End Rate Base before Deferred Tax Proratior	Sum of Lines 28 through 30		$38,386,750	$38,059,718	$41,347,631	$38,764,219	$36,278,024
	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/	$19,193,375	$39,867,191	$39,867,191	$40,055,925	$37,521,122
33	Proration Adjustment	Page 19 of 39, Line 40		$13,205	$20,023	$20,023	$40,876	$36,703
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$19,206,580	$39,887,214	$39,887,214	$40,096,801	$37,557,825
35	Pre-Tax ROR	Page 38 of 39, 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	Col (a) and (d): L 34 * L 35; Cols (b) through (c): L 34 * L 35 * L 36	2/	$1,580,702	$485,662	$2,797,055	$3,299,967	$3,091,009
38	Book Depreciation	Line 19		$815,545	$241,312	$1,389,778	$1,631,090	$1,631,090
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$2,396,246**	**$726,974**	**$4,186,833**	**$4,931,056**	**$4,722,099**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 39, 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 2025 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)
	Capital Repairs Deduction			
1	Plant Additions	Page 17 of 39, Line 3		$86,469,768
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.67%
3	Capital Repairs Deduction	Line 1 * Line 2		$25,655,580
4				
5	Bonus Depreciation			
6	Plant Additions	Line 1		$86,469,768
7	Plant Additions			$0
8	Less Capital Repairs Deduction	Line 3		$25,655,580
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$60,814,188
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0
12	Bonus Depreciation Rate	at 0%		0.00%
13	Total Bonus Depreciation Rate	Line 12		0.00%
14	Bonus Depreciation	Line 11 * Line 13		$0
15				
16	Remaining Tax Depreciation			
17	Plant Additions	Line 1		$86,469,768
18	Less Capital Repairs Deduction	Line 3		$25,655,580
19	Less Bonus Depreciation	Line 14		$0
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$60,814,188
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,280,532
23				
24	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$6,103,955
25	Cost of Removal	Page 17 of 39, Line 10		$7,612,192
26				
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$41,652,259

20 Year MACRS Depreciation

Line No.	(b)		(c)	(d)	(e)	(f)
3	NG MACRS basis:	Line 22, Column (a)			$60,814,188	
4					Annual	Cumulative
5	Fiscal Year			Prorated	MACRS	Tax Depr
6	FY Mar-2022		3.750%		$2,280,532	$41,652,259
7	FY Mar-2023 (Apr-May 2022)		7.219%	1.068%	$649,506	$42,301,764
8						
9	PPL Acquisition - May 25, 2022					
10	Book Cost	Line 1, Column (a)			$86,469,768	
11	Cumulative Book Depreciation	- Page 17 of 39, Line 20, Col (b)			($1,056,857)	
12	PPL MACRS basis:	Line 10(e) + Line 11(e)			$85,412,911	
13						
14	FY Mar-2023 (Jun-Mar 2023)		3.750%		$3,202,984	$3,202,984
15	Mar-2024		7.219%		$6,165,958	$9,368,942
16	Mar-2025		6.677%		$5,703,020	$15,071,962
17	Mar-2026		6.177%		$5,275,956	$20,347,918
18	Mar-2027		5.713%		$4,879,640	$25,227,557
19	Mar-2028		5.285%		$4,514,072	$29,741,630
20	Mar-2029		4.888%		$4,174,983	$33,916,613
21	Mar-2030		4.522%		$3,862,372	$37,778,985
22	Mar-2031		4.462%		$3,811,124	$41,590,109
23	Mar-2032		4.461%		$3,810,270	$45,400,379
24	Mar-2033		4.462%		$3,811,124	$49,211,503
25	Mar-2034		4.461%		$3,810,270	$53,021,773
26	Mar-2035		4.462%		$3,811,124	$56,832,897
27	Mar-2036		4.461%		$3,810,270	$60,643,167
28	Mar-2037		4.462%		$3,811,124	$64,454,291
29	Mar-2038		4.461%		$3,810,270	$68,264,561
30	Mar-2039		4.462%		$3,811,124	$72,075,685
31	Mar-2040		4.461%		$3,810,270	$75,885,955
32	Mar-2041		4.462%		$3,811,124	$79,697,079
33	Mar-2042		4.461%		$3,810,270	$83,507,349
34	Mar-2043		2.231%		$1,905,562	$85,412,911
35			100.000%		$85,412,911	
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 2025 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 39, Line 19. Note there are 2 columns to sum for FY23.	$815,545	$1,631,090	$1,631,090	$1,631,090
2	Bonus Depreciation	Page 14 of 39, Line 20	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 18 of 39, Line 22, column (a), thereafter, see the corresponding Fiscal Year on Page 17 of 39, Line 16. Note there are 2 columns to sum for FY23.	($2,280,532)	($3,852,490)	($6,165,958)	($5,703,020)
4	FY 2022 tax (gain)/loss on retirements	- Page 18 of 39, Line 24				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,464,987)	($2,221,400)	($4,534,868)	($4,071,930)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($307,647)	($466,494)	($952,322)	($855,105)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 18 of 39, Line 3	($25,655,580)			
9	Cost of Removal	- Page 18 of 39, Line 25	($7,612,192)			
10	Cumulative Book / Tax Timer	Line 8 + Line 9	($33,267,772)	$0	$0	$0
11	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
12	Deferred Tax Reserve	Line 10 * Line 11	($6,986,232)	$0	$0	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12	($7,293,879)	($466,494)	($952,322)	($855,105)
14	Net Operating Loss	Page 17 of 39, Line 26	$0	$0	$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	($7,293,879)	($466,494)	($952,322)	($855,105)
	Allocation of FY 2022 Estimated Federal NOL					
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,464,987)	($2,221,400)	($4,534,868)	($4,071,930)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	($33,267,772)	$0	$0	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	($34,732,759)	($2,221,400)	($4,534,868)	($4,071,930)
19	Total FY 2022 Federal NOL (Utilization)	- Page 17 of 39, Line 26 / 21%	$0	$0	$0	$0
20	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19	$0	$0	$0	$0
21	Allocated FY 2022 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19	$0	$0	$0	$0
22	Effective Tax Rate		21%	21%	21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22	$0	$0	$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	($307,647)	($466,494)	($952,322)	($855,105)

Line No.	Proration Calculation	Number of Days in Month (e)	Proration Percentage (f)	FY22 (g)	FY23 (h)	FY24 (i)	FY25 (j)
25	April	30	91.78%	($23,530)	($35,679)	($72,837)	($65,402)
26	May	31	83.29%	($21,353)	($32,378)	($66,097)	($59,350)
27	June	30	75.07%	($19,246)	($29,183)	($59,575)	($53,493)
28	July	31	66.58%	($17,068)	($25,881)	($52,834)	($47,441)
29	August	31	58.08%	($14,891)	($22,579)	($46,094)	($41,389)
30	September	30	49.86%	($12,784)	($19,384)	($39,571)	($35,532)
31	October	31	41.37%	($10,606)	($16,082)	($32,831)	($29,480)
32	November	30	33.15%	($8,499)	($12,887)	($26,308)	($23,623)
33	December	31	24.66%	($6,322)	($9,585)	($19,568)	($17,571)
34	January	31	16.16%	($4,144)	($6,284)	($12,828)	($11,519)
35	February	28	8.49%	($2,177)	($3,302)	($6,740)	($6,052)
36	March	31	0.00%	$0	$0	$0	$0
37	Total	365		($140,619)	($213,224)	($435,285)	($390,850)
38	Deferred Tax Without Proration	Line 24		($307,647)	($466,494)	($952,322)	($855,105)
39	Average Deferred Tax without Proration	Line 38 × 0.5		($153,824)	($233,247)	($476,161)	($427,553)
40	Proration Adjustment	Line 37 - Line 39		$13,205	$20,023	$40,876	$36,703

Column Notes:

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

(g) through (j) Current Year Line 24 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 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)	Fiscal Year 2025 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*	Docket 5209, P 33 of 33. Line 1	2/	$6,130,225	$35,305,558		
	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		$13,762,249	$79,260,362	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,762,249	$79,260,362		
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		$11,129,096	$64,095,350	$75,224,446	$75,224,446
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$13,762,249	$79,260,362	$0	$0
8	Depreciation Expense	Page 33 of 39, Line 62, Col (d)	2/	$7,383,490	$42,523,431	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$6,378,760	$36,736,931	$43,115,691	$43,115,691
10	Cost of Removal	Company's Record	2/	$1,142,377	$6,579,244		
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$7,521,136**	**$43,316,175**	**$50,837,312**	**$50,837,312**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	Page 31 of 39, Line 3, Col (e)	1/	3.16%	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 39, Column (a), Line 27; Col (b) = Page 21 of 39, Col (b), Lines 18,24,25 + Col (e), Line 15, Then remaining years from Page 21 of 39, Col (e)		$5,945,572	$34,751,583	$5,553,098	$5,136,173
16	Cumulative Tax Depreciation-NG	Col (a) = Line 15; then 0	3/	$5,945,572			
17	Cumulative Tax Depreciation-PPL	Col (b) = Line 15; then = Prior Year Line 17 + Current Year Line 15	3/		$34,751,583	$40,304,680	$45,440,853
18	Book Depreciation	Year 1 (Columns (a) and (b)) = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$175,840	$1,012,707	$2,377,093	$2,377,093
19	Cumulative Book Depreciation	Year 1 = Line 18; then = Prior Year Line 19 + Current Year Line 18		$175,840	$1,188,546	$3,565,639	$5,942,731
20	Book / Tax Timer	Line 15 - Line 18		$5,769,733	$33,738,876	$3,176,005	$2,759,081
21	Cumulative Book / Tax Timer -NG	Col (a) = Line 20, Column (a), Then = 0	3/	$5,769,733			
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/		$33,738,876	$36,914,881	$39,673,962
23	Cumulative Book / Tax Timer - Total	Line 21 + Line 22		$5,769,733	$33,738,876	$36,914,881	$39,673,962
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Line 23 × Line 24		$1,211,644	$7,085,164	$7,752,125	$8,331,532
26	Add: FY 2023 Federal NOL (Generation) / Utilization	Page 29 of 39 , Line 13 ,Col (f)	3/	$23,627,830	$0	$0	$0
27	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 25 through 26		$24,839,474	$7,085,164	$7,752,125	$8,331,532
	Rate Base Calculation:						
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$7,521,136	$43,316,175	$50,837,312	$50,837,312
29	Accumulated Depreciation	Year 1 (Cols (a) and (b)) = -Line 18; Then = -Line 19		($175,840)	($1,012,707)	($3,565,639)	($5,942,731)
30	Deferred Tax Reserve	-Line 27		($24,839,474)	($7,085,164)	($7,752,125)	($8,331,532)
31	Year End Rate Base before Deferred Tax Proratior	Sum of Lines 28 through 30		($17,494,177)	$35,218,304	$39,519,548	$36,563,048
	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/	($8,747,088)	$17,609,152	$28,621,838	$38,041,298
33	Proration Adjustment	Page 22 of 39, Line 40	2/	$108,647	$30,004	$28,628	$24,870
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		($8,638,441)	$17,639,156	$28,650,465	$38,066,167
35	Pre-Tax ROR	Page 38 of 39, Line 35		8.23%	8.23%	8.23%	8.23%
36	Proration	Line 13					
37	Return and Taxes	Line 34 x Line 35		($710,944)	$1,451,703	$2,357,933	$3,132,846
38	Book Depreciation	Line 18		$175,840	$1,012,707	$2,377,093	$2,377,093
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**($535,104)**	**$2,464,409**	**$4,735,026**	**$5,509,938**
40	Annual Revenue Requiement per Docket No. 22-53-EL FY 2024 Electric ISR Reconciliation, Page 1, Lines 5(b) and 5(c) or Page 5, Line 42(f) and 42(g)			($536,088)	$2,453,369	$4,710,545	
41	2023 and 2024 Tax True-Up			$984	$11,040	$24,481	

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 39, 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 31, Column (c). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 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)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction								
1	Plant Additions	Page 20 of 39, Line 3, Columns (a) through (c)		$13,762,249	$79,260,362		20 Year MACRS Depreciation		
2	Capital Repairs Deduction Rate	Per Tax Department	1/	20.09%	20.09%				
3	Capital Repairs Deduction	Line 1 * Line 2		$2,764,836	$15,923,407	MACRS basis:	Line 20, Column (a)	$10,997,413	
4								Annual	Cumulative
5	Bonus Depreciation					Fiscal Year		MACRS	Tax Depr
6	Plant Additions	Line 1		$13,762,249	$79,260,362	FY Mar-2023 (Apr-May 2022)	3.750%	$412,403	$5,945,572
7	Plant Additions			$0	$0				
8	Less Capital Repairs Deduction	Line 3		$2,764,836	$15,923,407	PPL Acquisition - May 25, 2022			
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$10,997,413	$63,336,955	Book Cost	Line 1, Column (a)	$13,762,249	
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	0.00%	Cumulative Book Depreciation	- Page 20 of 39, Line 18, Col (a)	($175,840)	
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	$0	MACRS basis from Acquisition:	Line 9(e) + Line 10(e)	$13,586,410	
12	Bonus Depreciation Rate	at 0%		0.00%	0.00%	MACRS basis (Jun-Mar 2023)	Line 20, Column (b)	$63,336,955	
13	Total Bonus Depreciation Rate	Line 12		0.00%	0.00%	Total MACRS Basis in 2022	Line 11(e) + Line 12(e)	$76,923,364	
14	Bonus Depreciation	Line 11 * Line 13		$0	$0				
15						FY Mar-2023 (Jun-Mar 2023)	3.750%	$2,884,626	$34,751,583
16	Remaining Tax Depreciation					Mar 2024	7.219%	$5,553,098	$40,304,680
17	Plant Additions	Line 1		$13,762,249	$79,260,362	Mar 2025	6.677%	$5,136,173	$45,440,853
18	Less Capital Repairs Deduction	Line 3		$2,764,836	$15,923,407	Mar 2026	6.177%	$4,751,556	$50,192,410
19	Less Bonus Depreciation	Line 14		$0	$0	Mar 2027	5.713%	$4,394,632	$54,587,041
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$10,997,413	$63,336,955	Mar 2028	5.285%	$4,065,400	$58,652,441
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	3.750%	Mar 2029	4.888%	$3,760,014	$62,412,455
22	Remaining Tax Depreciation	Line 20 * Line 21		$412,403	$2,375,136	Mar 2030	4.522%	$3,478,475	$65,890,930
23						Mar 2031	4.462%	$3,432,321	$69,323,250
24	FY23 (Gain)/Loss incurred due to retirements	Per Tax Department	1/	$1,625,957	$9,364,305	Mar 2032	4.461%	$3,431,551	$72,754,802
25	Cost of Removal	Page 20 of 39, Line 10		$1,142,377	$6,579,244	Mar 2033	4.462%	$3,432,321	$76,187,122
26						Mar 2034	4.461%	$3,431,551	$79,618,673
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$5,945,572	$34,242,093	Mar 2035	4.462%	$3,432,321	$83,050,994
28						Mar 2036	4.461%	$3,431,551	$86,482,545
29	Reconcilation of MACRS Tax Depreciation:					Mar 2037	4.462%	$3,432,321	$89,914,866
30	Apr 1 -May 24, 2022 Plant Additions	Line 1, Column (a)			$13,762,249	Mar 2038	4.461%	$3,431,551	$93,346,417
31	Cumulative Book Depreciaiton through May 24, 2022	Page 20 of 39, Line 18, Col (a)			($175,840)	Mar 2039	4.462%	$3,432,321	$96,778,738
32	2023 Plant Additions (Net Book) through Acquisition	Line 30 + Line 31			$13,586,410	Mar 2040	4.461%	$3,431,551	$100,210,289
33	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%	Mar 2041	4.462%	$3,432,321	$103,642,609
34	Tax Depreciation	Line 32 * Line 33			$509,489	Mar 2042	4.461%	$3,431,551	$107,074,161
35						Mar 2043	2.231%	$1,716,160	$108,790,321
36	MACRS Basis in May 25-Mar 2023 Plant Additions	Line 20, Column (b)			$63,336,955		100.00%	$76,923,364	
37	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%				
38	Tax Depreciation	Line 36 * Line 37			$2,375,135				
39									
40	Total MACRS Tax Depreciation	Sum of Lines 34, 38, Column (b)			$2,884,624				
41									

42 1/ The capital repairs percentage and tax loss on retirements are 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; and one-fourth (January 2023 thru March 2023) of PPL's CY2023 tax return.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 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 39, Line 18	$175,840	$1,012,707	$2,377,093	$2,377,093
2	Bonus Depreciation	- Page 21 of 39, Line 14	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 21 of 39, column (e), Lines 6 and 15 through 18	($412,403)	($2,884,626)	($5,553,098)	($5,136,173)
4	FY 2023 tax (gain)/loss on retirements	- Page 21 of 39, Line 24	($1,625,957)	($9,364,305)		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,862,520)	($11,236,225)	($3,176,005)	($2,759,081)
6	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($391,129)	($2,359,607)	($666,961)	($579,407)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	- Page 21 of 39, Line 3 ,Cols (a) and (b), Then = 0	($2,764,836)	($15,923,407)		
9	Cost of Removal	- Page 21 of 39, Line 25 ,Cols (a) and (b), Then = 0	($1,142,377)	($6,579,244)		
10	Cumulative Book / Tax Timer	Line 8 + Line 9	($3,907,213)	($22,502,651)	$0	$0
11	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%
12	Deferred Tax Reserve	Line 10 * Line 11	($820,515)	($4,725,557)	$0	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12	($1,211,644)	($7,085,164)	($666,961)	($579,407)
14	Net Operating Loss	- Page 20 of 39, Line 26	$0	$0	$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	($1,211,644)	($7,085,164)	($666,961)	($579,407)
	Allocation of FY 2023 Estimated Federal NOL					
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,862,520)	($11,236,225)	($3,176,005)	($2,759,081)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	($3,907,213)	($22,502,651)	$0	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	($5,769,733)	($33,738,876)	($3,176,005)	($2,759,081)
19	Total FY 2023 Federal NOL (Utilization)	- Page 20 of 39, Line 26 / 21%	$0	$0	$0	$0
20	Allocated FY 2023 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19	$0	$0	$0	$0
21	Allocated FY 2023 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19	$0	$0	$0	$0
22	Effective Tax Rate		21%	21%	21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22	$0	$0	$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	($391,129)	($2,359,607)	($666,961)	($579,407)

Line No.	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(g) FY23	(h) FY23	(i) FY24	(j) FY25
25	April	30	91.78%	($86,918)		($51,012)	($44,315)
26	May	31	83.29%	$0	($209,682)	($46,291)	($40,215)
27	June	30	75.07%		($188,989)	($41,723)	($36,246)
28	July	31	66.58%		($167,607)	($37,003)	($32,145)
29	August	31	58.08%		($146,225)	($32,282)	($28,044)
30	September	30	49.86%		($125,533)	($27,714)	($24,076)
31	October	31	41.37%		($104,151)	($22,993)	($19,975)
32	November	30	33.15%		($83,459)	($18,425)	($16,006)
33	December	31	24.66%		($62,077)	($13,705)	($11,906)
34	January	31	16.16%		($40,695)	($8,984)	($7,805)
35	February	28	8.49%		($21,382)	($4,721)	($4,101)
36	March	31	0.00%		$0	$0	$0
37	Total	365		($86,918)	($1,149,800)	($304,853)	($264,834)
38	Deferred Tax Without Proration	Line 24		($391,129)	($2,359,607)	($666,961)	($579,407)
39	Average Deferred Tax without Proration	Line 38 × 0.5		($195,565)	($1,179,804)	($333,481)	($289,703)
40	Proration Adjustment	Line 37 - Line 39		$108,647	$30,004	$28,628	$24,870

Column Notes:
(f) Sum of remaining days in the year (Col (e)) ÷ 365
(g) through (j) Current Year Line 24 ÷ 12 × Current Month Col (f)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2024 Actual Incremental Capital Investment

Line No.				Fiscal Year 2024 (a)	Fiscal Year 2025 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*	Docket 22-53-EL, Page 35 of 36, Line 1		$45,412,440	
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Docket 22-53-EL, Page 35 of 36, Line 13		$51,836,809	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$97,249,249	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$97,249,249	$0
5	Retirements	Company's Record		$35,642,212	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$61,607,037	$61,607,037
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$97,249,249	$0
8	Depreciation Expense	Page 33 of 39, Line 62, Col (d)		$49,906,920	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$47,342,329	$47,342,329
10	Cost of Removal	Company's Record		$9,246,273	
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$56,588,602**	**$56,588,602**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 31 of 39, Line 3, Col (e)	1/	3.16%	3.16%
13	Proration Percentage				
14	Vintage Year Tax Depreciation:				
15	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 24 of 39, Line 27, Column (a), Then = Page 24 of 39 , Column (d)		$69,885,547	$4,203,829
16	Cumulative Tax Depreciation	Prior Year Line 16 + Current Year Line 15		$69,885,547	$74,089,376
17	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$973,391	$1,946,782
18	Cumulative Book Depreciation	Prior Year Line 18 + Current Year Line 17		$973,391	$2,920,174
19	Cumulative Book / Tax Timer	Line 16 - Line 18		$68,912,156	$71,169,203
20	Effective Tax Rate			21.00%	21.00%
21	Deferred Tax Reserve	Line 19 * Line 20		$14,471,553	$14,945,533
22	Add: CY 2024 Federal NOL (Generation) / Utilization	Company's Record		$0	$0
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 21 through 22		$14,471,553	$14,945,533
	Rate Base Calculation:				
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$56,588,602	$56,588,602
25	Accumulated Depreciation	-Line 18		($973,391)	($2,920,174)
26	Deferred Tax Reserve	-Line 23		($14,471,553)	($14,945,533)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$41,143,658	$38,722,895
	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		$20,571,829	$39,933,276
29	Proration Adjustment	Page 25 of 39, Line 40		$186,128	$20,344
30	Average ISR Rate Base after Deferred Tax Proration	Line 29 + Line 30		$20,757,957	$39,953,621
31	Pre-Tax ROR	Page 38 of 39, Line 33		8.23%	8.23%
32	Proration	Line 13		100.00%	100.00%
33	Return and Taxes	Year 1 = Lines 30 * 31 * 32		$1,708,380	$3,288,183
34	Book Depreciation	Line 17		$973,391	$1,946,782
35	**Annual Revenue Requirement**	**Line 33 + Line 34**		**$2,681,771**	**$5,234,965**
36	Annual Revenue Requiement per Docket No. 22-53-EL FY 2024 Electric ISR Reconciliation, Page 1, Line 11(b) or Page 23, Line 35(a)			$2,882,298	
37	2024 Tax True-Up & Retirement Net of Tax Update			($200,527)	
38	2024 Tax True-Up			$24,448	
39	2024 Retirement Net of Tax Update			($224,975)	
40	Total Update			($200,527)	

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 39, Line 3, Col (e))

The Narragansett Electric Company
d/b/a Rhode Island Energy
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 39, Line 3		$97,249,249	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	40.12%				
3	Capital Repairs Deduction	Line 1 * Line 2		$39,016,399	MACRS basis:	Line 20	$58,232,850	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$97,249,249	Mar-2024	3.750%	$2,183,732	$69,885,547
7	Plant Additions			$0	Mar-2025	7.219%	$4,203,829	$74,089,376
8	Less Capital Repairs Deduction	Line 3		$39,016,399	Mar-2026	6.677%	$3,888,207	$77,977,584
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$58,232,850	Mar-2027	6.177%	$3,597,043	$81,574,627
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Mar-2028	5.713%	$3,326,843	$84,901,470
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Mar-2029	5.285%	$3,077,606	$87,979,076
12	Bonus Depreciation Rate	at 0%		0.00%	Mar-2030	4.888%	$2,846,422	$90,825,498
13	Total Bonus Depreciation Rate	Line 12		0.00%	Mar-2031	4.522%	$2,633,289	$93,458,787
14	Bonus Depreciation	Line 11 * Line 13		$0	Mar-2032	4.462%	$2,598,350	$96,057,137
15					Mar-2033	4.461%	$2,597,767	$98,654,904
16	Remaining Tax Depreciation				Mar-2034	4.462%	$2,598,350	$101,253,254
17	Plant Additions	Line 1		$97,249,249	Mar-2035	4.461%	$2,597,767	$103,851,021
18	Less Capital Repairs Deduction	Line 3		$39,016,399	Mar-2036	4.462%	$2,598,350	$106,449,371
19	Less Bonus Depreciation	Line 14		$0	Mar-2037	4.461%	$2,597,767	$109,047,139
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$58,232,850	Mar-2038	4.462%	$2,598,350	$111,645,488
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2039	4.461%	$2,597,767	$114,243,256
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,183,732	Mar-2040	4.462%	$2,598,350	$116,841,606
23					Mar-2041	4.461%	$2,597,767	$119,439,373
24	FY24 (Gain)/Loss incurred due to retirements	Per Tax Department	1/	$19,439,143	Mar-2042	4.462%	$2,598,350	$122,037,723
25	Cost of Removal	Page 23 of 39, Line 10		$9,246,273	Mar-2043	4.461%	$2,597,767	$124,635,490
26					Mar-2044	2.231%	$1,299,175	$125,934,665
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$69,885,547		100.00%	$58,232,850	

1/ The capital repairs percentage and tax loss on retirements are based on on three-fourths (April 2023 thru December 2023) of PPL's CY2023 tax return and one-fourth (January 2024 thru March 2024) of PPL's CY2024 tax return.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 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 39, Line 17		$973,391	$1,946,782
2	Bonus Depreciation	- Page 24 of 39, Line 14		$0	
3	Remaining MACRS Tax Depreciation	- Page 24 of 39, Col (d), starting with Line 6		($2,183,732)	($4,203,829)
4	Plan Year 2024 tax (gain)/loss on retirements	- Page 24 of 39, Line 24, Col (a), Then = 0		($19,439,143)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($20,649,484)	($2,257,047)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($4,336,392)	($473,980)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 24 of 39, Line 3, Col (a), Then = 0		($39,016,399)	
9	Cost of Removal	- Page 24 of 39, Line 25, Col (a), Then = 0		($9,246,273)	
10	Cumulative Book / Tax Timer	Line 8 + Line 9		($48,262,672)	$0
11	Effective Tax Rate			21.00%	21.00%
12	Deferred Tax Reserve	Line 10 * Line 11		($10,135,161)	$0
13	Total Deferred Tax Reserve	Line 7 + Line 12		($14,471,553)	($473,980)
14	Net Operating Loss	Page 23 of 39, Line 22		$0	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14		($14,471,553)	($473,980)
	Allocation of Plan Year 2024 Estimated Federal NOL				
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		($20,649,484)	($2,257,047)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10		($48,262,672)	$0
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17		($68,912,156)	($2,257,047)
19	Total Plan Year 2024 Federal NOL (Utilization)	- Page 23 of 39, Line 22 / 21%		$0	$0
20	Allocated Plan Year 2024 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19		$0	$0
21	Allocated Plan Year 2024 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19		$0	$0
22	Effective Tax Rate			21%	21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22		$0	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23		($4,336,392)	($473,980)
		(c)	(d)	(e)	(f)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY24	FY25
25	April	30	91.78%	($331,665)	($36,252)
26	May	31	83.29%	($300,973)	($32,897)
27	June	30	75.07%	($271,272)	($29,651)
28	July	31	66.58%	($240,581)	($26,296)
29	August	31	58.08%	($209,889)	($22,941)
30	September	30	49.86%	($180,188)	($19,695)
31	October	31	41.37%	($149,497)	($16,340)
32	November	30	33.15%	($119,795)	($13,094)
33	December	31	24.66%	($89,104)	($9,739)
34	January	31	16.16%	($58,413)	($6,385)
35	February	28	8.49%	($30,691)	($3,355)
36	March	31	0.00%	$0	$0
37	Total	365		($1,982,068)	($216,646)
38	Deferred Tax Without Proration	Line 24		($4,336,392)	($473,980)
39	Average Deferred Tax without Proration	Line 38 × 0.5		($2,168,196)	($236,990)
40	Proration Adjustment	Line 37 - Line 39		$186,128	$20,344

Column Notes:

(d)	Sum of remaining days in the Apr 1-Dec 31 period (Col (c)) ÷ 275
(e) through (f)	Current Year Line 24 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2025 Actual Incremental Capital Investment

Line No.				Fiscal Year 2025 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	Docket 23-48-EL, Page 38 of 38, Line 1		$63,286,991
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Docket 23-48-EL, Page 38 of 38, Line 13		$51,867,959
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$115,154,950
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$115,154,950
5	Retirements	Company's Record		$18,549,222
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$96,605,728
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$115,154,950
8	Depreciation Expense	Page 33 of 39, Line 62, Col (d)		$49,906,920
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$65,248,030
10	Cost of Removal	Company's Record		$22,657,398
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$87,905,428**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	Page 31 of 39, Line 3, Col (e)	1/	3.16%
13	Vintage Year Tax Depreciation:			
14	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 27 of 39, Line 27, Column (a), Then = Line Page 27 of 39 , Column (d)		$67,164,379
15	Cumulative Tax Depreciation-PPL	Prior Year Line 15 + Current Year Line 14		$67,164,379
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,526,371
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,526,371
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$65,638,008
19	Effective Tax Rate			21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$13,783,982
21	Add: CY 2025 Federal NOL (Generation) / Utilization	Company's Record		$0
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$13,783,982
	Rate Base Calculation:			
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$87,905,428
24	Accumulated Depreciation	-Line 17		($1,526,371)
25	Deferred Tax Reserve	-Line 22		($13,783,982)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$72,595,075
	Revenue Requirement Calculation:			
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 26 * 50%; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2		$36,297,538
28	Proration Adjustment	Page 28 of 39, Line 40		$72,701
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$36,370,239
30	Pre-Tax ROR	Page 38 of 39, Line 33		8.23%
31	Return and Taxes	Line 29 * Line 30		$2,993,271
32	Book Depreciation	Line 16		$1,526,371
33	**Annual Revenue Requirement**	**Line 31 + Line 32**		**$4,519,641**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 39, Line 3, Col (e))

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Incremental Capital Investments

Line No.				Fiscal Year 2025 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 26 of 39, Line 3		$115,154,950	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	30.32%				
3	Capital Repairs Deduction	Line 1 * Line 2		$34,914,981	MACRS basis:	Line 20	$80,239,969	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$115,154,950	Dec-2025	3.750%	$3,008,999	$67,164,379
7	Plant Additions			$0	Dec-2026	7.219%	$5,792,523	$72,956,902
8	Less Capital Repairs Deduction	Line 3		$34,914,981	Dec-2027	6.677%	$5,357,623	$78,314,525
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$80,239,969	Dec-2028	6.177%	$4,956,423	$83,270,948
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Dec-2029	5.713%	$4,584,109	$87,855,057
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Dec-2030	5.285%	$4,240,682	$92,095,740
12	Bonus Depreciation Rate	at 0%		0.00%	Dec-2031	4.888%	$3,922,130	$96,017,869
13	Total Bonus Depreciation Rate	Line 12		0.00%	Dec-2032	4.522%	$3,628,451	$99,646,321
14	Bonus Depreciation	Line 11 * Line 13		$0	Dec-2033	4.462%	$3,580,307	$103,226,628
15					Dec-2034	4.461%	$3,579,505	$106,806,133
16	Remaining Tax Depreciation				Dec-2035	4.462%	$3,580,307	$110,386,441
17	Plant Additions	Line 1		$115,154,950	Dec-2036	4.461%	$3,579,505	$113,965,946
18	Less Capital Repairs Deduction	Line 3		$34,914,981	Dec-2037	4.462%	$3,580,307	$117,546,253
19	Less Bonus Depreciation	Line 14		$0	Dec-2038	4.461%	$3,579,505	$121,125,758
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$80,239,969	Dec-2039	4.462%	$3,580,307	$124,706,066
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Dec-2040	4.461%	$3,579,505	$128,285,571
22	Remaining Tax Depreciation	Line 20 * Line 21		$3,008,999	Dec-2041	4.462%	$3,580,307	$131,865,878
23					Dec-2042	4.461%	$3,579,505	$135,445,383
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	1/	$6,583,001	Dec-2043	4.462%	$3,580,307	$139,025,690
25	Cost of Removal	Page 26 of 39, Line 10		$22,657,398	Dec-2044	4.461%	$3,579,505	$142,605,195
26					Dec-2045	2.231%	$1,790,154	$144,395,349
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$67,164,379		100.00%	$80,239,969	

1/ The capital repairs percentage and tax loss on retirements are based on on three-fourths (April 2024 thru December 2024) of PPL's CY2024 consolidated tax return. When PPL's CY2025 consolidated tax return is finalized in year 2026, these tax items will be updated to include one-fourth (January thru March 2025) of the CY 2025 tax return.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration		FY25 (a)
1	Book Depreciation	Page 26 of 39, Line 16	$1,526,371
2	Bonus Depreciation	Page 27 of 39, Line 14	$0
3	Remaining MACRS Tax Depreciation	- Page 27 of 39, Col (d), starting with Line 6	($3,008,999)
4	FY 2025 tax (gain)/loss on retirements	- Page 27 of 39, Line 24, Col (a), Then = 0	($6,583,001)
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($8,065,629)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($1,693,782)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 27 of 39, Line 3, Col (a), Then = 0	($34,914,981)
9	Cost of Removal	- Page 27 of 39, Line 25, Col (a), Then = 0	($22,657,398)
10	Cumulative Book / Tax Timer	Line 8 + Line 9	($57,572,379)
11	Effective Tax Rate		21.00%
12	Deferred Tax Reserve	Line 10 * Line 11	($12,090,200)
13	Total Deferred Tax Reserve	Line 7 + Line 12	($13,783,982)
14	Net Operating Loss	- Page 26 of 39, Line 21	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	($13,783,982)
	Allocation of FY 2025 Estimated Federal NOL		
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($8,065,629)
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	($57,572,379)
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	($65,638,008)
19	Total FY 2025 Federal NOL (Utilization)	- Page 26 of 39, Line 21 / 21%	$0
20	Allocated FY 2025 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19	$0
21	Allocated FY 2025 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19	$0
22	Effective Tax Rate		21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	($1,693,782)

	Proration Calculation	(c) Number of Days in Month	(d) Proration Percentage	(e) FY25
25	April	30	91.78%	($129,547)
26	May	31	83.29%	($117,559)
27	June	30	75.07%	($105,958)
28	July	31	66.58%	($93,970)
29	August	31	58.08%	($81,982)
30	September	30	49.86%	($70,381)
31	October	31	41.37%	($58,393)
32	November	30	33.15%	($46,792)
33	December	31	24.66%	($34,804)
34	January	31	16.16%	($22,816)
35	February	28	8.49%	($11,988)
36	March	31	0.00%	$0
37	Total	365		($774,190)
38	Deferred Tax Without Proration	Line 24		($1,693,782)
39	Average Deferred Tax without Proration	Line 38 × 0.5		($846,891)
40	Proration Adjustment	Line 37 - Line 39		$72,701

Column Notes:
(d) Sum of remaining days in the year (Col (c)) ÷ 365
(e) Current Year Line 24 ÷ 12 × Current Month Col (d)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
FY 2018 - 2025 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)	Fiscal Year 2024 (g)	Fiscal Year 2025 (h)
	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	$91,040,276	$110,253,323	$98,188,293	$114,637,174	$86,469,768	$93,022,611	$97,249,249	$115,154,950
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	$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	$0	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$16,197,276	$31,949,697	$67,003,710	$114,637,174	$86,469,768	$93,022,611	$97,249,249	$115,154,950
	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	$9,945,454	$8,093,515	$14,702,756	$10,426,121	$7,697,775	$7,721,621	$9,246,273	$22,657,398
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	$0	$0
7	Incremental Cost of Removal	Line 5 - Line 6	$1,685,747	$245,506	$11,264,831	$10,220,721	$7,612,192	$7,721,621	$9,246,273	$22,657,398
	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	$35,642,212	$18,549,222
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	$0	$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	$35,642,212	$18,549,222
	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	$0	$0
12	less: (NOL)/Utilization recovered in transmission rates	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11	($1,572,911)	$515,161	$0	$570,357	$248,590	$12,178,036	$0	$0
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 30 of 39, Line 12	($2,998,499)	$991,622	$0	$1,125,232	$482,315	$23,627,830	$0	$0
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	$0	$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	$0	$0

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 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 29 of 39, 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 Rhode Island Energy
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 Rhode Island Energy
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
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 31 of 39, Line 66 (c)				($1,435,572)
69		Plus: Comm Equipment Depreciation		Page 31 of 39, 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 31 of 39, Line 66 (c)				($1,435,572)
76		Plus: Comm Equipment Depreciation		Page 31 of 39, 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 2026 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	$98,188	$9,323	$107,511		($14,649)		$1,790,725
7	Accumulated Depr	$705,047				$54,155	($14,649)	($14,703)	$729,850
8	Net Plant	$992,816							$1,060,875
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	$114,637	$3,873	$118,510		($22,589)		$1,886,646
12	Accumulated Depr	$729,850				$57,246	($22,589)	($11,374)	$753,133
13	Net Plant	$1,060,875							$1,133,513
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	$86,470	$13,092	$99,562		($35,100)		$1,951,108
17	Accumulated Depr	$753,133				$59,937	($35,100)	($7,698)	$770,271
18	Net Plant	$1,133,513							$1,180,837
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	$1,951,108	$93,023	$11,660	$104,682		($17,798)		$2,037,992
22	Accumulated Depr	$770,271				$63,558	($17,798)	($8,431)	$807,600
23	Net Plant	$1,180,837							$1,230,393
24	Property Tax Expense	$33,955							$34,532
25	Effective Prop Tax Rate	2.88%							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	$2,037,992	$97,249	$7,008	$104,257		($35,642)		$2,106,607
27	Accumulated Depr	$807,600				$64,348	($35,642)	($9,246)	$827,059
28	Net Plant	$1,230,393							$1,279,548
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	$2,106,607	$115,155	$11,660	$14,407		($18,549)		$2,102,465
32	Accumulated Depr	$827,059				$67,503	($18,549)	($22,657)	$853,355
33	Net Plant	$1,279,548							$1,249,110
34	Property Tax Expense	$40,092							$38,715
35	Effective Prop Tax Rate	3.13%							3.10%
	Effective Tax Rate Calculation	**End of FY 2025**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2026**
36	Plant In Service	$2,102,465	$98,440	$7,008	$105,448		($30,361)		$2,177,551
37	Accumulated Depr	$853,355				$70,476	($30,361)	($15,709)	$877,761
38	Net Plant	$1,249,110							$1,299,791
39	Property Tax Expense	$38,715							$40,722
40	Effective Prop Tax Rate	3.10%							3.13%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2026 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**		
41	Incremental ISR Additions		$92,660			$111,243			$35,410	
42	Book Depreciation: base allowance on ISR eligible plant		($43,032)			($43,032)			$0	
43	Book Depreciation: current year ISR additions		($1,317)			($1,628)			($983)	
44	COR		$9,980			$7,949			$246	
45	Net Plant Additions		$58,291			$74,532			$34,673	
46	RY Effective Tax Rate		3.98%			3.98%			3.28%	
									1.91%	
47	ISR Year Effective Tax Rate	3.29%			3.23%					
48	RY Effective Tax Rate	3.98%	-0.69%		3.98%	-0.75%		3.23%		
49	RY Effective Tax Rate 5 mos for FY 2019		-0.69%		5 month	-0.31%		3.28%	-0.05%	
50	RY Net Plant times 5 mo rate	$746,900	-0.69%	($5,191)	$746,900	-0.31%	($2,338)		-0.03% 7 mos	
51	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)
52	FY 2015 Net Adds times ISR Year Effective Tax rate	$34,308	3.29%	$1,128	$32,324	1.35%	$435			
53	FY 2016 Net Adds times ISR Year Effective Tax rate	$33,535	3.29%	$1,102	$32,090	1.35%	$432	$16,819	1.88%	$317
54	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	3.29%	$1,256	$37,040	1.35%	$499	$34,673	1.88%	$653
55	FY 2018 Net Adds times ISR Year Effective Tax rate	$58,291	3.29%	$1,916	$55,850	1.35%	$752			
56	FY 2019 Net Adds times ISR Year Effective Tax rate				$74,532	1.35%	$1,003			
57	Total ISR Property Tax Recovery			$263			$800			$691

		(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**		
58	Incremental ISR Additions		$67,004			$114,637			$86,470	
59	Book Depreciation: base allowance on ISR eligible plant		$0			$0			($29,112)	
60	Book Depreciation: current year ISR additions		($995)			($1,464)			($816)	
61	COR		$11,265			$10,221			$7,612	
62	Net Plant Additions		$77,273			$123,394			$64,154	
63	RY Effective Tax Rate		3.38%			3.58%			3.66%	
64	ISR Property Tax Recovery on non-ISR									
65	ISR Year Effective Tax Rate	3.07%			2.94%			2.88%		
66	RY Effective Tax Rate	3.38%	-0.31%		3.58%	-0.64%		3.66%	-0.79%	
67	RY Effective Tax Rate 7 mos for FY 2019									
68	RY Net Plant times Rate Difference	$902,404	-0.31%	($2,825)	$853,576	* -0.64%	($5,427)	$833,223	* -0.79%	($6,574)
69	Non-ISR plant times rate difference	($2,269)	-0.31%	$7	($4,269)	* -0.64%	$27	($6,269)	* -0.79%	$49
70	FY 2018 Net Incremental times rate difference	$16,142	3.07%	$496	$15,464	* 2.94%	$455	$14,787	* 2.88%	$425
71	FY 2019 Net Incremental times rate difference	$32,833	3.07%	$1,008	$30,992	* 2.94%	$911	$29,152	* 2.88%	$838
72	FY 2020 Net Incremental times rate difference	$77,273	3.07%	$2,372	$75,283	* 2.94%	$2,214	$73,292	* 2.88%	$2,107
73	FY 2021 Net Incremental times rate difference				$123,394	* 2.94%	$3,629	$120,467	* 2.88%	$3,463
74	FY 2022 Net Adds times rate differenc							$64,154	* 2.88%	$1,844
75	Total ISR Property Tax Recovery			$1,059			$1,810			$2,154

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2026 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		
76	Incremental ISR Additions		$93,023			$97,249			$115,155	
77	Book Depreciation: base allowance on ISR eligible plant		($49,907)			($49,907)			($49,907)	
78	Book Depreciation: current year ISR additions		($1,189)			($973)			($1,526)	
79	COR		$7,722			$9,246			$22,657	
80	Net Plant Additions		$49,649			$55,615			$86,379	
81	RY Effective Tax Rate		3.66%			3.66%			3.66%	
82	ISR Property Tax Recovery on non-ISR									
83	ISR Year Effective Tax Rate	2.81%			3.13%			3.10%		
84	RY Effective Tax Rate	3.66%	-0.86%		3.66%	-0.53%		3.66%	-0.57%	
85	RY Effective Tax Rate 7 mos for FY 2019									
86	RY Net Plant times Rate Difference	$833,223	* -0.86%	($7,141)	$833,223	* -0.53%	($4,424)	$833,223	* -0.57%	($4,708)
87	Non-ISR plant times rate difference	($8,269)	* -0.86%	$71	($10,269)	* -0.53%	$55	($12,269)	* -0.57%	$69
88	FY 2018 Net Incremental times rate difference	$14,109	* 2.81%	$396	$13,432	* 3.13%	$421	$12,754	* 3.1%	$395
89	FY 2019 Net Incremental times rate difference	$27,311	* 2.81%	$767	$25,471	* 3.13%	$798	$23,630	* 3.1%	$732
90	FY 2020 Net Incremental times rate difference	$71,302	* 2.81%	$2,001	$69,312	* 3.13%	$2,172	$67,321	* 3.1%	$2,086
91	FY 2021 Net Incremental times rate difference	$117,539	* 2.81%	$3,299	$114,612	* 3.13%	$3,591	$111,684	* 3.1%	$3,461
92	FY 2022 Net Incremental times rate difference	$62,523	* 2.81%	$1,755	$60,892	* 3.13%	$1,908	$59,261	* 3.1%	$1,836
93	FY 2023 Net Incremental times rate difference	$49,649	* 2.81%	$1,394	$47,272	* 3.13%	$1,481	$44,895	* 3.1%	$1,391
94	FY 2024 Net Incremental times rate difference				$55,615	* 3.13%	$1,742	$53,668	* 3.1%	$1,663
95	FY 2025 Net Incremental times rate difference							$86,379	* 3.1%	$2,677
96	Total ISR Property Tax Recovery			$2,542			$7,742			$9,604

		(ab)	(ac)	(ad)
		Cumulative Increm. ISR Prop. Tax for FY2026		
97	Incremental ISR Additions		$98,440	
98	Book Depreciation: base allowance on ISR eligible plant		($49,907)	
99	Book Depreciation: current year ISR additions		($1,076)	
100	COR		$15,709	
101	Net Plant Additions		$63,166	
102	RY Effective Tax Rate		3.66%	
103	ISR Property Tax Recovery on non-ISR			
104	ISR Year Effective Tax Rate	3.13%		
105	RY Effective Tax Rate	3.66%	-0.53%	
106	RY Effective Tax Rate 7 mos for FY 2019			
107	RY Net Plant times Rate Difference	$833,223	* -0.53%	($4,424)
108	Non-ISR plant times rate difference	($14,269)	* -0.53%	$76
109	FY 2018 Net Incremental times rate difference	$12,076	* 3.13%	$378
110	FY 2019 Net Incremental times rate difference	$22,160	* 3.13%	$694
111	FY 2020 Net Incremental times rate difference	$65,331	* 3.13%	$2,047
112	FY 2021 Net Incremental times rate difference	$108,757	* 3.13%	$3,407
113	FY 2022 Net Incremental times rate difference	$57,630	* 3.13%	$1,806
114	FY 2023 Net Incremental times rate difference	$42,517	* 3.13%	$1,332
115	FY 2024 Net Incremental times rate difference	$51,722	* 3.13%	$1,620
116	FY 2025 Net Incremental times rate difference	$83,326	* 3.13%	$2,611
117	FY 2026 Net Incremental times rate difference	$63,166	* 3.13%	$1,979
118	Total ISR Property Tax Recovery			$11,526

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2026 ISR Property Tax Recovery Adjustment 4 (continued)
(000s)

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 39, L 6(a) + Page 5 of 39, L 6(a)+Page 10 of 39, L(a)+, L6(a)) × 0.0316+Page 8 of 3935(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 39, 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)
24(h)	Per Company's Book
25(h)	Line 24(h) ÷ 23(h)
41(a) - 57(i)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
58(j) - 75(o)	
	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
58(q) - 72(r)	Docket No. 5098 Attachment 1C, Page 26 of 29, 38(j) to 50(k)
73(p)	=73(m) - (Page 13 of 39, Line 19(b) ÷ 1000
74(p)	=62(q)
73(q) - 74(q)	=65(p)
73(r) - 74(r)	=73(p) to 74(p) x 73(q) to 74(q)
75(r)	Sum of Lines 68(r) through 74(r)
76(t)	Page 20 of 39, Line 3(a) through 3(c) / 1000
77(t)	Page 20 of 39, Line 8(a) through 8(c) / 1000
78(t)	Page 20 of 39, Line 19(a) through 19(c) /1000
79(t)	Page 20 of 39, Line 10(a) through 10(c) / 1000
80(t)	Sum of Lines 76(t) through 79(t)
81(t)	=63(q)
83(s)	=25(h)

Line Notes	
84(s)	=81(t)
84(t)	83(s) -84(s)
86(s)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000]
87(s)	=69(p) - 2000
88(s)	=70(p) - Page 2 of 39, Line 19(i) / 1000
89(s)	=71(p) - (Page 5 of 39, Line 19(e) + Page 8 of 39, Line 35(o))/1000
90(s)	=72(p) - (Page 10 of 39, Line 19(d) through 19(f)) / 1000
91(s)	=73(p) - (Page 13 of 39, Line 19(c) through 19(e)) / 1000
92(s)	=74(p) - (Page 17 of 39, Line 19(b) through 19(d)) / 1000
93(s)	=80(t)
86(t)-87(t)	=84(t)
88(t)-93(t)	=83(s)
86(u) - 93(u)	=86(s) to 93(s) x 86(t) to 93(t)
96(u)	Sum of Lines 86(u) through 93(u)
97(ac)	Page do not print of 39, Line 3(a) / 1000
98(ac)	Page do not print of 39, Line 8(a) / 1000
99(ac)	Page do not print of 39, Line 16(a) / 1000
100(ac)	Page do not print of 39, Line 10(a) / 1000
101(ac)	Sum of Lines 76(ac) through 79(ac)
102(ac)	=81(z)
104(ab)	=40(h)
105(ab)	=102(ac)
105(ac)	104(ab) -105(ab)
107(ab)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000]
108(ab)	=87(y) - 2000
109(ab)	=88(y) - Page 2 of 39, Line 19(j) / 1000
110(ab)	=89(y) - (Page 5 of 39, Line 19(i) + Page 8 of 39, Line 35(aa))/1000
111(ab)	=90(y) - Page 10 of 39, Line 19(h) / 1000
112(ab)	=91(y) - Page 13 of 39, Line 19(g) / 1000
113(ab)	=92(y) - Page 17 of 39, Line 19(f) / 1000
114(ab)	=93(y) - Page 20 of 39, Line 18(e) / 1000
115(ab)	=94(y) - Page 23 of 39, Line 17(c) / 1000
116(ab)	=95(y) - Page 26 of 39, Line 16(b) / 1000
117(ab)	=101(ac)
107(ac)-108(ac)	=105(ac)
109(ac)-117(ac)	=104(ab)
107(ad)-117(ad)	=107(ab) to 117(ab) x 107(ac) to 117(ac)
118(ad)	Sum of Lines 97(ad) through 100(ad)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 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 2025 Incremental Capital Investment

Line No.			Fiscal Year 2025 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in FY 2025 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	Fiscal Year 2025 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 18, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$63,286,991**	**$0**	$63,286,991
	Discretionary Capital				
2	Cumulative CY 2024 Discretionary Capital ADDITIONS	Page do not print of 39, Line 4	$616,544,988		
3	FY 2025 Discretionary Capital ADDITIONS	Section 2, Chart 18, Col 2	$51,867,959		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$668,412,947		
5	Cumulative FY 2024 Discretionary Capital SPENDING	Page do not print of 39, Line 7	$682,900,975		
6	FY 2025 Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$71,003,993		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$753,904,968		
8	Cumulative FY 2024 Approved Discretionary Capital SPENDING	Page do not print of 39, Line 10	$684,416,478		
9	FY 2025 Approved Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$71,003,993		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$755,420,471		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$668,412,947		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Page do not print of 39, Line 11	$616,544,988		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$51,867,959**	**$0**	**$51,867,959**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$115,154,950**	**$0**	**$115,154,950**
15	Intangible Assets included in Total Allowed Discretionary Capital	Section 2, Chart 10, Column 2 note			$0
16	**Total Allowed Discretionary Capital Included in non-Intangible Rate Base Current Year**	Line 14 - Line 15			**$115,154,950**

Attachment JDO-2

Revenue Requirement Adjustment for FY 2025 Capital Consolidated Soft Budget Overspend
FY 2025 Electric Infrastructure, Safety, and Reliability Plan Reconciliation

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Fiscal Year 2025 Revenue Requirement on FY 2025 Overspend

Line No.		Changes to Calculation to quantify full year	Full Year Revenue Requirement above cap 2025 (a)	Full Year Revenue Requirement at cap 2025 (b)	Revenue Requirement Adjustment 2025 (c)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*		$69,938,688	$50,675,000	$19,263,688
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)		$57,519,751	$67,944,678	($10,424,927)
3	Total Allowed Capital Included in Rate Base (non-intangible)		$127,458,439	$118,619,678	$8,838,761
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year		$127,458,439	$118,619,678	$8,838,761
5	Retirements		$18,549,222	$18,549,222	$0
6	Net Depreciable Capital Included in Rate Base		$108,909,217	$100,070,456	$8,838,761
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base		$127,458,439	$118,619,678	$8,838,761
8	Depreciation Expense		$49,906,920	$49,906,920	$0
9	Incremental Capital Amount		$77,551,518	$68,712,757	$8,838,761
10	Cost of Removal		$22,657,398	$22,657,398	$0
11	**Total Net Plant in Service**		**$100,208,916**	**$91,370,155**	**$8,838,761**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	1/	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:				
14	Tax Depreciation and Year 1 Basis Adjustments		$64,633,286	$61,722,416	$2,910,870
15	Cumulative Tax Depreciation-PPL		$64,633,286	$61,722,416	$2,910,870
16	Book Depreciation	**Full year book depreciation vs. half**	$3,441,531	$3,162,226	$279,305
17	Cumulative Book Depreciation		$3,441,531	$3,162,226	$279,305
18	Cumulative Book / Tax Timer		$61,191,755	$58,560,190	$2,631,565
19	Effective Tax Rate		21.00%	21.00%	21.00%
20	Deferred Tax Reserve		$12,850,268	$12,297,640	$552,629
21	Add: CY 2025 Federal NOL (Generation) / Utilization		$0	$0	$0
22	Net Deferred Tax Reserve before Proration Adjustment		$12,850,268	$12,297,640	$552,629
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base		$100,208,916	$91,370,155	$8,838,761
24	Accumulated Depreciation		($3,441,531)	($3,162,226)	($279,305)
25	Deferred Tax Reserve		($12,850,268)	($12,297,640)	($552,629)
26	Year End Rate Base before Deferred Tax Proration		$83,917,117	$75,910,289	$8,006,828
	Revenue Requirement Calculation:				
27	Average Rate Base before Deferred Tax Proration Adjustment	**Year end rate base vs. average**	$83,917,117	$75,910,289	$8,006,828
28	Proration Adjustment		($12,660)	($7,148)	($5,512)
29	Average ISR Rate Base after Deferred Tax Proration		$83,904,456	$75,903,141	$8,001,315
30	Pre-Tax ROR		8.23%	8.23%	8.23%
31	Return and Taxes	**Full year return and taxes**	$6,905,337	$6,246,829	$658,508
32	Book Depreciation	**Full year book depreciation**	$3,441,531	$3,162,226	$279,305
33	**Annual Revenue Requirement**		**$10,346,868**	**$9,409,055**	**$937,813**

Column Notes:
(a) Value of the FY 2025 revenue requirement (with the overspend) that has been adjusted to reflect a full year (removing the half year convention for book depreciation and return)
(b) Value of the FY 2025 revenue requirement (without the overspend) that has been adjusted to reflect a full year (removing the half year convention for book depreciation and return)
(c) Column (a) less Column (b) = Value of full year revenue requirement adjustment on overspend of $8,838,761

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Incremental Capital Investments

Line No.				Fiscal Year 2025 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 1 of 5, Line 3, Col (b)		$118,619,678	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	30.32%				
3	Capital Repairs Deduction	Line 1 * Line 2		$35,965,486	MACRS basis:	Line 20	$82,654,192	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$118,619,678	Mar-2026	3.750%	$3,099,532	$61,722,416
7	Plant Additions			$0	Mar-2027	7.219%	$5,966,806	$67,689,222
8	Less Capital Repairs Deduction	Line 3		$35,965,486	Mar-2028	6.677%	$5,518,820	$73,208,042
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$82,654,192	Mar-2029	6.177%	$5,105,549	$78,313,592
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Mar-2030	5.713%	$4,722,034	$83,035,626
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Mar-2031	5.285%	$4,368,274	$87,403,900
12	Bonus Depreciation Rate	at 0%		0.00%	Mar-2032	4.888%	$4,040,137	$91,444,037
13	Total Bonus Depreciation Rate	Line 12		0.00%	Mar-2033	4.522%	$3,737,623	$95,181,659
14	Bonus Depreciation	Line 11 * Line 13		$0	Mar-2034	4.462%	$3,688,030	$98,869,689
15					Mar-2035	4.461%	$3,687,203	$102,556,893
16	Remaining Tax Depreciation				Mar-2036	4.462%	$3,688,030	$106,244,923
17	Plant Additions	Line 1		$118,619,678	Mar-2037	4.461%	$3,687,203	$109,932,126
18	Less Capital Repairs Deduction	Line 3		$35,965,486	Mar-2038	4.462%	$3,688,030	$113,620,156
19	Less Bonus Depreciation	Line 14		$0	Mar-2039	4.461%	$3,687,203	$117,307,360
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$82,654,192	Mar-2040	4.462%	$3,688,030	$120,995,390
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2041	4.461%	$3,687,203	$124,682,593
22	Remaining Tax Depreciation	Line 20 * Line 21		$3,099,532	Mar-2042	4.462%	$3,688,030	$128,370,623
23					Mar-2043	4.461%	$3,687,203	$132,057,827
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0	Mar-2044	4.462%	$3,688,030	$135,745,857
25	Cost of Removal	Page 1 of 5, Line 10, Col (b)		$22,657,398	Mar-2045	4.461%	$3,687,203	$139,433,060
26					Mar-2046	2.231%	$1,844,015	$141,277,075
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$61,722,416		100.00%	$82,654,192	

1/ Per Tax Department
2/ Per Tax Department

Business Use

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		FY25 (a)
1	Book Depreciation	Page 1 of 5, Line 16, Col (b)	$3,162,226
2	Bonus Depreciation	Page 2 of 5, Line 14, Col (a)	$0
3	Remaining MACRS Tax Depreciation	- Page 2 of 5, Col (d), starting with Line 6	($3,099,532)
4	FY 2025 tax (gain)/loss on retirements	- Page 2 of 5, Line 24, Col (a), Then = 0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$62,694
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$13,166
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 2 of 5, Line 3, Col (a), Then = 0	($35,965,486)
9	Cost of Removal	- Page 2 of 5, Line 25, Col (a), Then = 0	($22,657,398)
10	Cumulative Book / Tax Timer	Line 8 + Line 9	($58,622,884)
11	Effective Tax Rate		21.00%
12	Deferred Tax Reserve	Line 10 * Line 11	($12,310,806)
13	Total Deferred Tax Reserve	Line 7 + Line 12	($12,297,640)
14	Net Operating Loss	- Page 1 of 5, Line 21	$0
15	Net Deferred Tax Reserve	Line 13 + Line 14	($12,297,640)
	Allocation of FY 2025 Estimated Federal NOL		
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	$62,694
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10	($58,622,884)
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17	($58,560,190)
19	Total FY 2025 Federal NOL (Utilization)	- Page 1 of 5, Line 21, Col (b) / 21%	$0
20	Allocated FY 2025 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19	$0
21	Allocated FY 2025 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19	$0
22	Effective Tax Rate		21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22	$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23	$13,166

		(b)	(c)	(d)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY25
25	April	30	91.78%	$1,007
26	May	31	83.29%	$914
27	June	30	75.07%	$824
28	July	31	66.58%	$730
29	August	31	58.08%	$637
30	September	30	49.86%	$547
31	October	31	41.37%	$454
32	November	30	33.15%	$364
33	December	31	24.66%	$271
34	January	31	16.16%	$177
35	February	28	8.49%	$93
36	March	31	0.00%	$0
37	Total	365		$6,018
38	Deferred Tax Without Proration	Line 24		$13,166
39	Average Deferred Tax without Proration	**Full Year vs. Average**		$13,166
40	Proration Adjustment	Line 37 - Line 39		($7,148)

Column Notes:

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

(d) Current Year Line 24 ÷ 12 × Current Month Col (c)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2026 Incremental Capital Investments

Line No.				Fiscal Year 2026 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 1 of 5, Line 3, Col (a)		$127,458,439	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	30.32%				
3	Capital Repairs Deduction	Line 1 * Line 2		$38,645,399	MACRS basis:	Line 20	$88,813,040	
4							Annual	Cumulative
5	Bonus Depreciation				Calendar Year			
6	Plant Additions	Line 1		$127,458,439	Mar-2026	3.750%	$3,330,489	$64,633,286
7	Plant Additions			$0	Mar-2027	7.219%	$6,411,413	$71,044,699
8	Less Capital Repairs Deduction	Line 3		$38,645,399	Mar-2028	6.677%	$5,930,047	$76,974,746
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$88,813,040	Mar-2029	6.177%	$5,485,981	$82,460,728
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Mar-2030	5.713%	$5,073,889	$87,534,616
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Mar-2031	5.285%	$4,693,769	$92,228,386
12	Bonus Depreciation Rate	at 0%		0.00%	Mar-2032	4.888%	$4,341,181	$96,569,567
13	Total Bonus Depreciation Rate	Line 12		0.00%	Mar-2033	4.522%	$4,016,126	$100,585,693
14	Bonus Depreciation	Line 11 * Line 13		$0	Mar-2034	4.462%	$3,962,838	$104,548,531
15					Mar-2035	4.461%	$3,961,950	$108,510,480
16	Remaining Tax Depreciation				Mar-2036	4.462%	$3,962,838	$112,473,318
17	Plant Additions	Line 1		$127,458,439	Mar-2037	4.461%	$3,961,950	$116,435,268
18	Less Capital Repairs Deduction	Line 3		$38,645,399	Mar-2038	4.462%	$3,962,838	$120,398,106
19	Less Bonus Depreciation	Line 14		$0	Mar-2039	4.461%	$3,961,950	$124,360,055
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$88,813,040	Mar-2040	4.462%	$3,962,838	$128,322,893
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2041	4.461%	$3,961,950	$132,284,843
22	Remaining Tax Depreciation	Line 20 * Line 21		$3,330,489	Mar-2042	4.462%	$3,962,838	$136,247,681
23					Mar-2043	4.461%	$3,961,950	$140,209,630
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0	Mar-2044	4.462%	$3,962,838	$144,172,468
25	Cost of Removal	Page 1 of 5, Line 10, Col (a)		$22,657,398	Mar-2045	4.461%	$3,961,950	$148,134,418
26					Mar-2046	2.231%	$1,981,419	$150,115,837
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$64,633,286		100.00%	$88,813,040	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**			FY25 (a)
1	Book Depreciation	Page 1 of 5, Line 16, Col (a)		$3,441,531
2	Bonus Depreciation	Page 4 of 5, Line 14, Col (a)		$0
3	Remaining MACRS Tax Depreciation	- Page 4 of 5, Col (d), starting with Line 6		($3,330,489)
4	FY 2025 tax (gain)/loss on retirements	- Page 4 of 5, Line 24, Col (a), Then = 0		$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		$111,042
6	Effective Tax Rate			21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		$23,319
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 4 of 5, Line 3, Col (a), Then = 0		($38,645,399)
9	Cost of Removal	- Page 4 of 5, Line 25, Col (a), Then = 0		($22,657,398)
10	Cumulative Book / Tax Timer	Line 8 + Line 9		($61,302,797)
11	Effective Tax Rate			21.00%
12	Deferred Tax Reserve	Line 10 * Line 11		($12,873,587)
13	Total Deferred Tax Reserve	Line 7 + Line 12		($12,850,268)
14	Net Operating Loss	- Page 1 of 5, Line 21		$0
15	Net Deferred Tax Reserve	Line 13 + Line 14		($12,850,268)
	Allocation of FY 2025 Estimated Federal NOL			
16	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		$111,042
17	Cumulative Book/Tax Timer Not Subject to Proration	Line 10		($61,302,797)
18	Total Cumulative Book/Tax Timer	Line 16 + Line 17		($61,191,755)
19	Total FY 2025 Federal NOL (Utilization)	- Page 1 of 5, Line 21, Col (a) / 21%		$0
20	Allocated FY 2025 Federal NOL Not Subject to Proration	(Line 17 / Line 18) * Line 19		$0
21	Allocated FY 2025 Federal NOL Subject to Proration	(Line 16 / Line 18) * Line 19		$0
22	Effective Tax Rate			21%
23	Deferred Tax Benefit subject to proration	Line 21 * Line 22		$0
24	Net Deferred Tax Reserve subject to proration	Line 7 + Line 23		$23,319
		(b)	(c)	(d)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY25
25	April	30	91.78%	$1,784
26	May	31	83.29%	$1,618
27	June	30	75.07%	$1,459
28	July	31	66.58%	$1,294
29	August	31	58.08%	$1,129
30	September	30	49.86%	$969
31	October	31	41.37%	$804
32	November	30	33.15%	$644
33	December	31	24.66%	$479
34	January	31	16.16%	$314
35	February	28	8.49%	$165
36	March	31	0.00%	$0
37	Total	365		$10,659
38	Deferred Tax Without Proration	Line 24		$23,319
39	Average Deferred Tax without Proration	**Full Year vs. Average**		$23,319
40	Proration Adjustment	Line 37 - Line 39		($12,660)

Column Notes:

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

(d) Current Year Line 24 ÷ 12 × Current Month Col (c)

PRE-FILED DIRECT TESTIMONY

OF

NATALIE HAWK

August 1, 2025

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 primarily are 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 degree in Business Administration with a major in Accounting from Kutztown University. In 1998, I received a Master's degree in Business Administration 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") 2026 Electric Infrastructure, Safety and Reliability ("ISR") Plan Filing, Docket No. 24-54-EL and the FY 2024 Electric ISR Plan Reconciliation Filing in Docket No. 22-53-EL.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the FY 2025 tax updates used to calculate accumulated deferred income taxes ("ADIT") in rate base for the revenue requirement in this FY 2025 Electric ISR filing. In addition, my testimony also discusses tax updates to FY 2024 and FY2023, which resulted in "true-ups" to the revenue requirement adjustment as reflected on Attachment JDO-1 to the pre-filed direct testimony of Company witness Jeffrey D. Oliveira ("Attachment JDO-1") on Page 1 of 39, Lines 15 and 16. Next, my testimony discusses FY 2023 and FY 2024 revenue requirement adjustments for tax related formula corrections to the FY 2018 and FY 2019 vintage years as reflected on Attachment JDO-1, Page 1 of 39, Lines 17 and 18. Finally, my testimony discusses the impacts of the above noted updates and corrections to the FY 2025, FY 2024 and FY 2023 hold harmless revenue credit calculations, as reflected on Attachment JDO-1, Page 1 of 39, Lines 21, 22 and 23, and also shown on Attachments NH-1, NH-2 and NH-3, respectively.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring Attachments NH-1, NH-2 and NH-3 for the FY 2025, 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 2025 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 30.32% and the tax loss on retirements of $6,583,001 to calculate ADIT for the FY 2025 rate base and revenue requirement. These revised estimates were based on three-quarters of the Company's 2024 calendar year tax return results, representing the April through December 2024 period. Although the Company does not expect to file its final 2024 tax return until October of 2025, 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 2025 tax activity for the ISR, the Company will sum three-quarters of its 2024 tax return activity, as will be reflected in this filing, and one-quarter of its 2025 tax return activity, representing the January through March 2025 period, to be updated in a subsequent ISR filing. The Company's 2025 tax return will not be filed with the Internal Revenue Service ("IRS") until October of 2026. The Company expects to finalize and reflect one-quarter of its 2025 tax return results in the tax updates to FY 2025 in the FY 2026 ISR Reconciliation, which will necessitate a tax true-up.

Q. Are there any tax updates to the FY 2024 revenue requirement reflected in the FY 2025 Electric ISR Reconciliation?

A. Yes, the Company has revised its vintage FY 2024 revenue requirement to reflect the following updates in Attachment JDO-1: (1) actual capital repairs deduction rate of 40.12%, as shown on Page 24, Line 2; and (2) actual tax loss on retirements of $19.439.143, as shown on Page 24, Line 24, Column (a).In order to finalize tax results for the FY 2024 period, the Company was required to refer to two separate tax returns.

The first tax return represents calendar year 2023 and is used to derive the April 1 through December 31, 2023, activity for FY 2024. The second tax return represents calendar year 2024 and is used to derive the January 1 through March, 31, 2024 activity for FY 2024. PPL's 2024 tax return will not be filed with the IRS until October 2025, but as previously stated, PPL does not anticipate any further changes to the tax information required for or relevant to the FY 2024 period. The impact of these changes created a net increase in the revenue requirement of $59,934, which is made up of an FY 2024 income tax upward true-up adjustment of $24,448 found on Attachment JDO-1, Page 1 of 39, Line 38, Column (a) and an FY 2024 hold harmless upward true-up adjustment of $35,486, found on Attachment JDO-1, Page 1 of 39, Line 22.

Q. Are there any tax updates to the FY 2023 revenue requirement reflected in the FY 2025 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 20.09%, as shown on Page 21, Line 2; and (2) actual tax loss on retirements of $10,990,262, as shown on Page 21, Line 24, Columns (a) and (b). Although the tax returns supporting the tax updates in the FY 2024 reconciliation were completed, the company discovered that the software reports used to support the capital repairs deduction rate and the tax loss on retirements for the FY 2023 Electric ISR reconciliation were not appropriate due to a misunderstanding of data presented. The impact of these changes created a net increase in the revenue requirement of $65,001, which is made up of an FY 2023 income tax true-up adjustment of $36,505 and an FY 2023 hold harmless true-up adjustment of $28,496, found on Attachment JDO-1, Page 1 of 39, Lines 16 and 23, respectively.

Q. Are there any formula corrections that impact the FY 2023 and FY 2024 revenue requirement reflected in the FY 2025 Electric ISR Reconciliation?

A. Yes, there is a total revenue requirement reduction of $61,475 for FY 2023 and FY 2024 as reflected on Attachment JDO-1, Page 1 of 39, Line 17, Column (b) for a formula correction related to the set-up in tax basis on the intangible property received as part of PPL Rhode Island Holdings, LLC's 2022the acquisition of 100 percent of the outstanding common stock of the Company from National Grid USA. The adjustment reflects a decrease of $28,282 for FY 2023 and a decrease of $33,193 for FY 2024 and can be found on Attachment JDO-1, Page 5 of 39, Line 44, Columns (f) and (g), respectively. For FY 2024 a second formula correction was made, which related to the FY 2018 vintage year tax proration calculation and resulted in a revenue requirement reduction of $345 found on Attachment JDO-1, Page 1 of 39, Line 18 and on Page 2 of 39, Line 42, Column (h).

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 2025. Among the vintage years, only FY 2018 incremental ISR investment created excess deferred income 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 2025 revenue requirement as shown on Line 27, Page 2 of Attachment JDO-1.

Q. Does the updated FY 2025 revenue requirement include bonus depreciation as a result of the 2017 Tax Act?

A. Yes. As indicated in the Company's FY 2025 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 2025 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2025 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 pre-acquisition 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

[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.

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 2025 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 2025 revenue requirement by the calculated hold harmless amounts totaling $1,897,113 as shown on Attachment JDO-1, Page 1, Lines 21, 22 and 23, Column (b) or in Attachments NH-1, Page 1, Line 23(a), NH-2, Page 1, Line 23(e) and NH-3, Page 1, Line 23(e).

[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, NH-2 and NH-3 show the calculation of the hold harmless credits to the FY 2025 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 2025 and Attachments NH-2 and NH-3 reflect the hold harmless revenue requirement true-up adjustment for FY 2024 and FY 2023, respectively. Page 1 of Attachments NH-1, NH-2 and NH-3 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 2025, the hold harmless adjustment reduced the revenue requirement by $1,961,095, as reflected on Attachment NH-1, Page 1, Line 16. This hold harmless adjustment decreased by $42,892 from the $2,003,987 estimate calculated for the FY 2025 Electric ISR Plan filing due to the FY 2023 tax updates for the repairs reduction rate and the tax loss on retirements, and the tax related formula corrections discussed above. These same tax updates created a $35,486 decrease for FY 2024 and a $28,496 decrease for FY 2023 hold harmless true-up adjustments, as shown on Attachments NH-2 and NH-3, Page 1, Line 23, Column (e), respectively. As mentioned previously, the Company discovered that the software reports used to support the capital repairs deduction rate and the tax loss on retirements for the FY 2023 Electric ISR reconciliation were not appropriate due to a misunderstanding of data presented. The process of capturing tax data for Electric ISR filings is now established and finalized and should limit any adjustments after a tax return is filed.

IV. Conclusion

Q. Does this conclude your testimony?

A. Yes.

Index of Attachments

Attachment NH-1

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

Impact of Elimination of ADIT and Hold Harmless Commitment for the FY 2025 Reconciliation
Fiscal Year 2025 - April 2024-March 2025

Inputs

1	Tax Rate		**21.00%**	
	Electric Distribution			
2	Long Term Debt		**48.350%**	
3	Short Term Debt		**0.600%**	
4	Preferred Stock		**0.100%**	
5	Debt Weighting	Lines 2+3+4	**49.050%**	
6	Equity Weighting	1 - Line 5	**50.950%**	
7	Long Term Debt Rate		**4.620%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.585%**	
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)	Page 2. Line 9, Column (c)	$ 211,407,906	Fiscal Year 2025
14	Rate Base - NG (before sale)	Page 2. Line 9, Column (f)	$ 187,579,297	Fiscal Year 2025
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ 23,828,609**	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 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**	
			(a)	(b)	(c) = (a) - (b)	
16	Rate Base after Acqusition	Line 13	211,407,906	211,407,906	-	
17	ADIT Adjustment	- Line 15	-	(23,828,609)	23,828,609	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**211,407,906**	**187,579,297**	**23,828,609**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,754,384	4,218,499	535,885	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	9,990,318	8,864,271	1,126,047	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,655,654	2,356,325	299,329	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**17,400,356**	**15,439,095**	**1,961,261**	
23	Revenue Adjustment for Fiscal Year 2025	- Line 15 * Line 11	(1,961,095)	-	(1,961,095)	Note 1
24	**Total Revenue**	**Lines 23 + 24**	**15,439,261**	**15,439,095**	**166**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,218,499	4,218,499	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,356,360	2,356,325	35	
27	**Net Income**	**Lines 24 - 25 - 26**	**8,864,402**	**8,864,271**	**131**	

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	7,377,453
29	Cash Tax Benefit at 21%	Line 28 * Line 1	1,549,265
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	1,961,095

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 2025**								
2	FY 2018	11,712,158	100%	11,712,158		12,473,657	100%	12,473,657	
3	FY 2019	23,951,955	100%	23,951,955		20,997,015	100%	20,997,015	
4	FY 2019 Intangible	340,830	100%	340,830		292,917	100%	292,917	
5	FY 2020	38,351,580	100%	38,351,580		34,321,162	100%	34,321,162	
6	FY 2021	61,427,391	100%	61,427,391		57,900,279	100%	57,900,279	
7	FY 2022	37,557,825	100%	37,557,825		33,015,419	100%	33,015,419	
8	FY 2023	38,066,167	100%	38,066,167		28,578,848	100%	28,578,848	
9		211,407,906		211,407,906	Page 2, Line 13	187,579,297		187,579,297	Page 2, Line 14

Attachment NH-2

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

Impact of Elimination of ADIT and Hold Harmless Commitment for the FY 2025 Reconciliation
Fiscal Year 2024 - April 2023-March 2024

Inputs

1	Tax Rate		**21.00%**	
	Electric Distribution			
2	Long Term Debt		**48.350%**	
3	Short Term Debt		**0.600%**	
4	Preferred Stock		**0.100%**	
5	Debt Weighting	Lines 2+3+4	**49.050%**	
6	Equity Weighting	1 - Line 5	**50.950%**	
7	Long Term Debt Rate		**4.620%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.585%**	
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)	Page 2. Line 9, Column (c)	$ 213,602,770	Fiscal Year 2024
14	Rate Base - NG (before sale)	Page 2. Line 9, Column (f)	$ 204,029,396	Fiscal Year 2024
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ 9,573,374**	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 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 for FY2024 per FY2024 Electric Reconciliation Filed in Docket 22-53-EL, Attachment NH-1	FY2024 Adjustment for FY2025 Reconciliation
			(a)	(b)	(c) = (a) - (b)		(d)	(e) = (c) - (d)
16	Rate Base after Acqusition	Line 13	213,602,770	213,602,770	-		-	-
17	ADIT Adjustment	- Line 15	-	(9,573,374)	9,573,374		10,004,562	(431,188)
18	**Adjusted Rate Base**	**Lines 16 + 17**	**213,602,770**	**204,029,396**	**9,573,374**		**10,004,562**	**(431,188)**
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,803,745	4,588,448	215,297		224,994	(9,697)
20	Equity Return (9.275%)	Lines 18 * 6 * 10	10,094,039	9,641,639	452,400		472,777	(20,377)
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,683,226	2,562,967	120,259		125,675	(5,416)
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**17,581,010**	**16,793,054**	**787,956**		**823,446**	**(35,490)**
23	Revenue Adjustment for Fiscal Year 2025	- Line 15 * Line 11	(787,890)	-	(787,890)	Note 1	(823,376)	35,486
24	**Total Revenue**	**Lines 23 + 24**	**16,793,120**	**16,793,054**	**66**		**70**	**(4)**
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,588,448	4,588,448	-			-
26	Tax Expense	(Lines 24 - 25) * Line 1	2,562,981	2,562,967	14		15	(1)
27	**Net Income**	**Lines 24 - 25 - 26**	**9,641,691**	**9,641,639**	**52**		**55**	**(3)**

	Impact of Transaction		
28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	2,963,967
29	Cash Tax Benefit at 21%	Line 28 * Line 1	622,433
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	787,890

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 (a)	Prorated (b)	Post-Acquisition After Proration (c)		No Acquisition (d)	Prorated (e)	No Acquisition After Proration (f)	
1	**Plan Year 2024**								
2	FY 2018	12,437,771	100%	12,437,771		13,080,233	100%	13,080,233	
3	FY 2019	25,415,046	100%	25,415,046		22,325,832	100%	22,325,832	
4	FY 2019 Intangible	827,213	100%	827,213		683,474	100%	683,474	
5	FY 2020	40,827,767	100%	40,827,767		36,580,247	100%	36,580,247	
6	FY 2021	65,347,707	100%	65,347,707		61,311,713	100%	61,311,713	
7	FY 2022	40,096,801	100%	40,096,801		35,127,512	100%	35,127,512	
8	FY 2023	28,650,465	100%	28,650,465		34,920,385	100%	34,920,385	
9		213,602,770		213,602,770	Page 2, Line 13	204,029,396		204,029,396	Page 2, Line 14

Attachment NH-3

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

Impact of Elimination of ADIT and Hold Harmless Commitment for the FY 2025 Reconciliation
Fiscal Year 2023 - April 2022-March 2023

Inputs

1	Tax Rate		**21.00%**	
	Electric Distribution			
2	Long Term Debt		**48.350%**	
3	Short Term Debt		**0.600%**	
4	Preferred Stock		**0.100%**	
5	Debt Weighting	Lines 2+3+4	**49.050%**	
6	Equity Weighting	1 - Line 5	**50.950%**	
7	Long Term Debt Rate		**4.620%**	
8	Short Term Debt Rate		**1.760%**	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	**4.585%**	
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)	Page 2. Line 9, Column (c)	$ 196,668,369	Fiscal Year 2023
14	Rate Base - NG (before sale)	Page 2. Line 9, Column (f)	$ 198,430,317	Fiscal Year 2023
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ (1,761,948)**	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 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 for FY2023 per FY2024 Electric Reconciliation Filed in Docket 22-53-EL, Attachment NH-2	FY2023 Adjustment for FY2025 Reconciliation
			(a)	(b)	(c) = (a) - (b)		(d)	(e) = (c) - (d)
16	Rate Base after Acqusition	Line 13	196,668,369	196,668,369	-		-	-
17	ADIT Adjustment	- Line 15	-	1,761,948	(1,761,948)		(1,415,692)	(346,256)
18	**Adjusted Rate Base**	**Lines 16 + 17**	**196,668,369**	**198,430,317**	**(1,761,948)**		**(1,415,692)**	**(346,256)**
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,422,905	4,462,529	(39,624)		(31,838)	(7,787)
20	Equity Return (9.275%)	Lines 18 * 6 * 10	9,293,785	9,377,048	(83,263)		(66,900)	(16,364)
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,470,500	2,492,633	(22,133)		(17,784)	(4,349)
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**16,187,190**	**16,332,210**	**(145,020)**		**(116,521)**	**(28,499)**
23	Revenue Adjustment for Fiscal Year 2025	- Line 15 * Line 11	145,008	-	145,008	Note 1	116,512	28,496
24	**Total Revenue**	**Lines 23 + 24**	**16,332,198**	**16,332,210**	**(12)**		**(9)**	**(3)**
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,462,529	4,462,529	-			-
26	Tax Expense	(Lines 24 - 25) * Line 1	2,492,630	2,492,633	(3)		(2)	(1)
27	**Net Income**	**Lines 24 - 25 - 26**	**9,377,039**	**9,377,048**	**(9)**		**(7)**	**(2)**

Impact of Transaction

28	Transaction-related Tax Deduction	- Line 23 * (1-Line 1) / Line 1	(545,506)
29	Cash Tax Benefit at 21%	Line 28 * Line 1	(114,556)
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	(145,008)

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 (a)	Prorated (b)	Post-Acquisition After Proration (c)		No Acquisition (d)	Prorated (e)	No Acquisition After Proration (f)	
1	**Plan Year 2023**								
2	FY 2018	13,401,008	100%	13,401,008		13,692,590	100%	13,692,590	
3	FY 2019	25,251,386	100%	25,251,386		23,676,167	100%	23,676,167	
4	FY 2019 Intangible	1,122,333	100%	1,122,333		892,693	100%	892,693	
5	FY 2020	41,062,934	100%	41,062,934		38,895,030	100%	38,895,030	
6	FY 2021	66,942,779	100%	66,942,779		64,812,217	100%	64,812,217	
7	FY 2022	39,887,214	100%	39,887,214		37,306,371	100%	37,306,371	
8	FY 2023	9,000,715	100%	9,000,715		19,155,249	100%	19,155,249	
9		196,668,369		196,668,369	Page 2, Line 13	198,430,317		198,430,317	Page 2, Line 14

PRE-FILED DIRECT TESTIMONY

OF

TYLER G. SHIELDS

August 1, 2025

Table of Contents

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

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. By whom are you employed and in what capacity?

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

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts degree in Economics from the University of Connecticut in 2013. In March 2015, I began my professional 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 PPL

Services Corporation in my current role and in mid-2024 continued in my current role, but as an employee of the Company.

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

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 2023 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 FY 2024 Electric RDM Reconciliation filing in Docket No. 24-18-EL, the Company's Gas RDM Reconciliation filing in Docket No. 24-29-NG and Docket No. 25-22-NG, the Company's 2024 DAC filing in Docket No. 24-29-NG, the Company's proposed FY 2026 Gas ISR Plan in Docket No. 24-55-NG, the Company's proposed FY 2026 Electric ISR Plan in Docket No. 24-54-EL, the Company's 2025 Annual Retail Rate Filing in Docket No. 25-04-EL, the Company's

FY 2025 Electric RDM Reconciliation filing in Docket No. 25-15-EL, and the Company's FY 2025 Gas RDM Reconciliation filing in Docket No. 25-22-NG.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present 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") 2025 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 2025 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 2023 CapEx and O&M reconciliations;
- the status of the credit of the FY 2024 CapEx and O&M reconciliations;
- the calculation of the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2025; 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 2025 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2025 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 2023 CapEx net over-recovery reconciliation balance, as well as the status of the recovery from customers of the FY 2024 CapEx net under-recovery reconciliation balance;
- Section V presents the results of the FY 2025 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the final status of the recovery from customers of the FY 2023 O&M under-recovery reconciliation balance, as well as the status of the recovery from customers of the FY 2024 O&M under-recovery reconciliation balance; and
- Section VI presents the rate class bill impact analysis.

III. Summary of FY 2025 Capex and O&M Reconciliations

Q. Please summarize the results of the FY 2025 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2025 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 $5.4 million; the result of the O&M reconciliation is a net under-recovery of approximately $0.3 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 each 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 (i) the annual CapEx revenue requirement on actual cumulative ISR capital investment to actual billed revenue generated from the CapEx Factors (the "CapEx Reconciliation"), and (ii) the actual O&M expense incurred to actual billed revenue generated from the O&M Factors (the "O&M Reconciliation"). 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. <u>Capex Reconciliation and Proposed Capex Reconciling Factors</u>

Q. What is the result of the CapEx Reconciliation for FY 2025?

A. The FY 2025 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, 2024 through March 31, 2025 of approximately $39.8 million. Line (4) reflects the CapEx revenue requirement on actual cumulative ISR capital investment of approximately $45.1 million. Line (6) identifies the net under-recovery by rate class of the CapEx revenue requirement, which totals approximately $5.4 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 2025 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 $5.4 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 2023 CapEx reconciliation. The net recovery of the FY 2023 CapEx reconciliation balance is presented on page 3. Of the $8.9 million net over-recovery for FY 2023 to be returned to customers via CapEx Reconciling Factors approved by the PUC, the Company returned to customers $8.8 million from October 1, 2023 through September 30, 2024. The remaining balance is a net over-recovery amount of approximately $0.1 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's residual balance associated with the FY 2023 reconciliation as an adjustment to the FY 2025 CapEx reconciliation balance.

Q. How is the Company proposing to recover the FY 2025 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's forecasted kWh deliveries for the period October 1, 2025 through September 30, 2026 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 2024 CapEx reconciliation?

A. Yes. The status of the FY 2024 CapEx reconciliation net over-recovery balance is presented in Attachment TGS-2, page 4. As of June 30, 2025, the balance reflects a remaining net under-recovery of approximately $0.5 million, which the Company will continue to recover from customers through September 30, 2025.

V. <u>O&M Reconciliation and Proposed O&M Reconciling Factor</u>

Q. What is the result of the O&M reconciliation for FY 2025?

A. The O&M reconciliation for FY 2025 is presented in Attachment TGS-3, page 1. Line (1) shows the actual O&M expense for FY 2025 of approximately $13.9 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, 2024 through March 31, 2025 of approximately $13.6 million. Line (3) shows the difference of approximately $0.3 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 of the under-recovery resulting from the FY 2023 O&M reconciliation. The recovery from customers of the under-recovered balance is presented on page 3. Of the $1,193,683 under-recovery that formed the basis for the O&M Reconciling Factor approved by the PUC, the Company recovered from customers $1,178,990 from October 1, 2023 through September 30, 2024, leaving $14,693to yet be returned to customers. As described in Docket No. 4682, the Company is including the residual balance as an adjustment to the FY 2025 O&M reconciliation balance.

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.

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 $329,680 on Line (5) is divided by the forecasted kWh during the period October 1, 2025 through September 30, 2026, on Line (6), resulting in a charge of $0.00004 ¢ 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 2024 O&M reconciliation under-recovery?

A. Yes. The status of the balance from the FY 2024 O&M reconciliation is presented in Attachment TGS-3, page 4, line 6. As of June 30, 2025, there is a remaining under-recovery balance of approximately $0.3 million, which the Company will continue to recover from customers through September 30, 2025.

Q. How does the Company propose to credit or recover the residual balance as of September 30, 2025?

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 2024 O&M reconciliation in the FY 2026 ISR Reconciliation Filing and include the residual balance of the FY 2024 O&M reconciliation with the results of the FY 2026 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 $0.00095 per kWh and the proposed O&M Reconciling Factor of $0.00004 per kWh as compared to the current CapEx Reconciling Factor of $0.00010 per kWh and current O&M Reconciling Factor of $0.00010 on a typical residential customer receiving Last Resort Service and using 500 kWh per month is an increase of $0.42, or approximately 0.3%, from $138.80 to $139.22.

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 also has submitted its 2025 Renewable Energy Growth Program Reconciliation filing in June 2025 in which the Company proposed a factor, effective October 1, 2025. The Company will file a Summary of Retail Delivery Rates tariff reflecting all rates proposed for October 1, 2025 in compliance with the PUC's orders in this proceeding and the 2025 Renewable Energy Growth Program Reconciliation proceedings.

VIII. Conclusion

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment TGS-1

FY 2025 ISR Plan Annual Reconciliation Summary

FY 2025 ISR Plan Annual Reconciliation Summary

		CapEx	O&M	Total
		(a)	(b)	(c)
(1)	Actual Revenue Requirement	$ 45,141,242	$13,922,884	$59,064,126
(2)	Revenue Billed	$39,753,514	$13,607,897	$53,361,411
(3)	Total Over/(Under) Recovery	($5,387,728)	($314,987)	($5,702,715)

(1)	Column (a): Attachment JDO-1, Page 1 of 39:		
	Line (19), Column (b): Total Capital Investment Component of Revenue Requirement	$	47,976,168
	Line (21) + (22) + (23), Column (b): Per Tax Hold Harmless Adjustment	$	(1,897,113)
	Line (25), Column (b): FY 2025 Overspend Adjustment	$	(937,813)
	Total Net Capital Investment Component of Revenue Requirement	$	45,141,242
	Column (b): Attachment JDO-1, Page 1 of 39, 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 2025 ISR Plan
For the Recovery/(Refund) Period October 1, 2025 through September 30, 2026

		Total	Residential A-16 / A-60	Small C&I C-06	General C&I G-02	200 kW Demand B-32 / G-32	Lighting S-05/S-06 S-10/S-14	Propulsion X-01
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	Actual FY2025 Capital Investment Revenue Requirement	$45,141,242						
(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 FY2025 Capital Investment Revenue Requirement	$45,141,242	$25,060,557	$4,641,458	$7,249,397	$7,663,613	$513,346	$12,871
(5)	CapEx Revenue Billed	$39,753,514	$21,610,171	$3,692,129	$6,905,266	$7,105,492	$423,477	$16,978
(6)	Total Over/(Under) Recovery for FY 2025	($5,387,728)	($3,450,386)	($949,329)	($344,131)	($558,121)	($89,868)	$4,107
(7)	Remaining Over/(Under) For FY 2023	$66,924	$222,802	($26,926)	($91,336)	($43,176)	$7,957	($2,397)
(8)	Total Over/(Under) Recovery	($5,320,804)	($3,227,583)	($976,255)	($435,467)	($601,297)	($81,912)	$1,710
(9)	Forecasted kWhs - October 1, 2025 through September 30, 2026	7,664,288,774	3,389,304,500	748,105,980	1,228,559,202	2,244,037,145	28,648,840	25,633,107
(10)	Proposed Class-specific CapEx Reconciling Factor Charge/(Credit) per kWh		$0.00095	$0.00130	$0.00035	$0.00026	$0.00285	($0.00006)

(1)	Column (a): Attachment JDO-1, Page 1 of 39:		
	Line (19), Column (b): Total Capital Investment Component of Revenue Requirement	$	47,976,168
	Line (21) + (22) + (23), Column (b): Per Tax Hold Harmless Adjustment	$	(1,897,113)
	Line (25), Column (b): FY 2025 Overspend Adjustment	$	(937,813)
	Total Net Capital Investment Component of Revenue Requirement	$	45,141,242

(2) per RIPUC 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, 2024 through March 31, 2025
For the Recovery/Refund Period October 1, 2025 through September 30, 2026

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-24	$ 501,481.00	$ (135,787)	$637,268	$ 62,186.00	$ (17,078)	$79,264	$ 174,382.00	$ (58,160)	$232,542	$ (29,786.00)	$ (64,067)	$34,281
	May-24	$ 1,097,531.00	($297,080)	$1,394,611	$ 233,545.00	($37,286)	$270,831	$ 424,037.00	($132,192)	$556,229	$ 426,413.00	($154,223)	$580,636
	Jun-24	$ 1,269,118.00	($343,587)	$1,612,705	$ 251,450.00	($40,503)	$291,953	$ 433,788.00	($148,717)	$582,505	$ 495,281.00	($170,396)	$665,677
	Jul-24	$ 1,848,897.00	($500,583)	$2,349,480	$ 309,063.00	($47,011)	$356,074	$ 491,101.00	($178,607)	$669,708	$ 520,598.00	($189,873)	$710,471
	Aug-24	$ 2,075,125.00	($561,664)	$2,636,789	$ 335,695.00	($48,987)	$384,682	$ 789,906.00	($204,915)	$994,821	$ 425,223.00	($202,118)	$627,341
	Sep-24	$ 1,503,578.00	($406,932)	$1,910,510	$ 275,438.00	($41,787)	$317,225	$ 688,137.00	($161,251)	$849,388	$ 536,319.00	($160,609)	$696,928
	Oct-24	$ 1,123,668.00	($304,065)	$1,427,733	$ 274,419.00	($34,868)	$309,287	$ (111,959.00)	($129,445)	$17,486	$ 384,957.00	($139,161)	$524,118
	Nov-24	$ 1,177,031.00	($178,901)	$1,355,932	$ 232,313.00	($5,544)	$237,857	$ 428,053.00	($88,817)	$516,870	$ 424,131.00	($78,922)	$503,053
	Dec-24	$ 1,694,667.00	$23,677	$1,670,990	$ 324,736.00	$36,182	$288,554	$ 496,459.00	($26,617)	$523,076	$ 746,238.00	($93,313)	$839,551
	Jan-25	$ 2,105,012.00	$29,290	$2,075,722	$ 357,502.00	$39,154	$318,348	$ 855,303.00	($42,633)	$897,936	$ 355,216.00	($61,269)	$416,485
	Feb-25	$ 1,980,960.00	$27,475	$1,953,485	$ 376,957.00	$41,732	$335,225	$ 181,077.00	($23,886)	$204,963	$ 758,852.00	($42,203)	$801,055
	Mar-25	$ 1,719,263.00	$23,904	$1,695,359	$ 339,320.00	$37,579	$301,741	$ 517,962.00	($30,612)	$548,574	$ 737,412.00	($57,552)	$794,964
(2)	Apr-25	$ 902,134.00	$ 12,547	$889,587	$ 226,097.00	$ 25,009	$201,088	$ 295,218.00	$ (15,950)	$311,168	$ (123,628.00)	$ (34,560)	($89,068)
	Total	$18,998,465	($2,611,706)	$21,610,171	$3,598,721	$ (93,408)	$3,692,129	$5,663,464	($1,241,802)	$6,905,266	$5,657,226	($1,448,266)	$7,105,492

		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-24	$ 5,123.00	$ (148)	$5,271	$ 265.00	$ (282)	$547
	May-24	$ 15,875.00	($1,230)	$17,105	$ 748.00	($773)	$1,521
	Jun-24	$ 22,676.00	($1,898)	$24,574	$ 691.00	($712)	$1,403
	Jul-24	$ 29,443.00	($2,517)	$31,960	$ 677.00	($697)	$1,374
	Aug-24	$ 71,939.00	($6,173)	$78,112	$ 762.00	($785)	$1,547
	Sep-24	$ 25,528.00	($2,103)	$27,631	$ -	$0	$0
	Oct-24	$ 31,134.00	($2,566)	$33,700	$ 1,381.00	($1,423)	$2,804
	Nov-24	$ 44,112.00	$3,745	$40,367	$ 668.00	($629)	$1,297
	Dec-24	$ 51,999.00	$15,252	$36,747	$ 850.00	($560)	$1,410
	Jan-25	$ 58,835.00	$17,255	$41,580	$ 870.00	($552)	$1,422
	Feb-25	$ 47,033.00	$13,790	$33,243	$ 914.00	($580)	$1,494
	Mar-25	$ 41,977.00	$12,302	$29,675	$ 802.00	($509)	$1,311
(2)	Apr-25	$ 33,179.00	$ 9,667	$23,512	$ 519.00	$ (329)	$848
	Total	$478,853	$55,376	$423,477	$9,147	($7,831)	$16,978

(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)

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	$8,875,873		$ 4,779,292		$452,216		$1,685,339		$1,916,982
(2)	CapEx Reconciling Factors			($0.00151)		($0.00064)		($0.00140)		($0.00086)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-23	($282,462)	92,432,176	($139,573)	24,570,994	($15,725)	40,386,076	($56,541)	80,388,898	($69,134)
	Nov-23	($617,866)	204,049,146	($308,114)	53,987,946	($34,552)	86,596,772	($121,235)	174,837,917	($150,361)
	Dec-23	($663,958)	230,077,905	($347,418)	53,880,784	($34,484)	88,450,180	($123,830)	178,599,427	($153,596)
	Jan-24	($757,905)	277,908,357	($419,642)	60,009,074	($38,406)	98,860,158	($138,404)	183,064,155	($157,435)
	Feb-24	($698,489)	242,297,438	($365,869)	59,883,395	($38,325)	100,715,355	($141,001)	174,439,855	($150,018)
	Mar-24	($699,176)	231,704,413	($349,874)	61,382,696	($39,285)	106,715,629	($149,402)	187,878,826	($161,576)
	Apr-24	($658,468)	214,911,942	($324,517)	63,773,838	($40,815)	99,283,813	($138,997)	178,038,655	($153,113)
	May-24	($622,784)	196,741,787	($297,080)	58,259,578	($37,286)	94,423,094	($132,192)	179,329,490	($154,223)
	Jun-24	($705,813)	227,541,098	($343,587)	63,285,551	($40,503)	106,226,075	($148,717)	198,134,621	($170,396)
	Jul-24	($919,288)	331,512,063	($500,583)	73,455,317	($47,011)	127,576,171	($178,607)	220,782,444	($189,873)
	Aug-24	($1,024,642)	371,963,070	($561,664)	76,541,607	($48,987)	146,367,713	($204,915)	235,020,381	($202,118)
	Sep-24	($772,682)	269,491,664	($406,932)	65,292,581	($41,787)	115,179,583	($161,251)	186,754,214	($160,609)
(4)	Oct-24	($385,416)	126,911,684	($191,637)	34,336,762	($21,976)	58,273,704	($81,583)	101,983,779	($87,706)
(5)	Total	($8,808,949)		($4,556,490)		($479,142)		($1,776,675)		($1,960,158)
(6)	Ending Over/(Under) Recovery	$66,924		$222,802		($26,926)		($91,336)		($43,176)

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		$36,091		$5,953
(2)	CapEx Reconciling Factors		($0.00095)		($0.00034)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-23	1,265,540	($1,202)	843,158	($287)
	Nov-23	2,964,561	($2,816)	2,317,257	($788)
	Dec-23	4,053,200	($3,851)	2,290,753	($779)
	Jan-24	3,540,882	($3,364)	1,923,642	($654)
	Feb-24	2,703,459	($2,568)	2,081,043	($708)
	Mar-24	(1,639,872)	$1,558	1,755,762	($597)
	Apr-24	371,502	($353)	1,979,932	($673)
	May-24	1,295,076	($1,230)	2,274,093	($773)
	Jun-24	1,998,323	($1,898)	2,095,397	($712)
	Jul-24	2,649,616	($2,517)	2,050,750	($697)
	Aug-24	6,498,127	($6,173)	2,308,037	($785)
	Sep-24	2,213,514	($2,103)	-	$0
(4)	Oct-24	1,701,877	($1,617)	2,637,046	($897)
(5)	Total		($28,134)		($8,350)
(6)	Ending Over/(Under) Recovery		$7,957		($2,397)

(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 revenue
(6) Line (1) + Line (5)

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

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

		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	$179,421		($304,093)		($481,700)		$355,607		$774,464
(2)	CapEx Reconciling Factors - 10/2024			($0.00151)		($0.00064)		($0.00140)		($0.00086)
(3)	CapEx Reconciling Factors - 11/2024			$0.00010		$0.00074		($0.00032)		($0.00038)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(4)	Oct-24	($226,112)	74,455,312	($112,428)	20,144,357	($12,892)	34,187,449	($47,862)	59,830,851	($51,455)
	Nov-24	($349,069)	193,827,022	($178,901)	40,512,975	($5,544)	88,267,143	($88,817)	115,215,803	($78,922)
	Dec-24	($45,379)	236,769,911	$23,677	48,894,683	$36,182	83,179,137	($26,617)	245,561,575	($93,313)
	Jan-25	($18,755)	292,896,693	$29,290	52,911,454	$39,154	133,228,356	($42,633)	161,233,240	($61,269)
	Feb-25	$16,328	274,754,002	$27,475	56,393,937	$41,732	74,642,817	($23,886)	111,061,292	($42,203)
	Mar-25	($14,888)	239,039,172	$23,904	50,781,899	$37,579	95,663,490	($30,612)	151,451,815	($57,552)
	Apr-25	($5,861)	203,386,394	$20,339	54,783,229	$40,540	80,798,638	($25,856)	147,424,713	($56,021)
	May-25	($32,803)	187,779,378	$18,778	43,114,638	$31,905	98,396,301	($31,487)	168,694,946	($64,104)
	Jun-25	($46,369)	213,216,101	$21,322	46,082,113	$34,101	97,260,348	($31,123)	209,788,134	($79,719)
	Jul-25	$0	-	$0	-	$0	-	$0	-	$0
	Aug-25	$0	-	$0	-	$0	-	$0	-	$0
	Sep-25	$0	-	$0	-	$0	-	$0	-	$0
(5)	Oct-25	$0	-	$0	-	$0	-	$0	-	$0
(6)	Total	($722,908)		($126,544)		$242,757		($348,893)		($584,558)
(7)	Ending Over/(Under) Recovery	($543,487)		($430,637)		($238,943)		$6,714		$189,906

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		($168,991)		$4,134
(2)	CapEx Reconciling Factors - 10/2024		($0.00095)		($0.00034)
	CapEx Reconciling Factors - 11/2024		$0.00516		($0.00026)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(4)	Oct-24	998,441	($949)	1,547,077	($526)
	Nov-24	2,930,928	$3,745	2,023,702	($629)
	Dec-24	2,955,743	$15,252	2,152,024	($560)
	Jan-25	3,343,941	$17,255	2,121,883	($552)
	Feb-25	2,672,429	$13,790	2,230,434	($580)
	Mar-25	2,384,024	$12,302	1,956,317	($509)
	Apr-25	3,036,852	$15,670	2,051,451	($533)
	May-25	2,456,943	$12,678	2,203,646	($573)
	Jun-25	1,865,046	$9,624	2,207,196	($574)
	Jul-25	-	$0	-	$0
	Aug-25	-	$0	-	$0
	Sep-25	-	$0	-	$0
(5)	Oct-25	-	$0	-	$0
(6)	Total		$99,367		($5,036)
(7)	Ending Over/(Under) Recovery		($69,624)		($902)

(1) Docket No. 22-53-EL, Attachment PUC 4-2-2 (TGS-2), Page 1, Line (10
(2) Docket No. 22-53-EL, Attachment PUC 4-2-2 (TGS-2), Page 4, Line (2)
(3) Docket No. 22-53-EL, Attachment PUC 4-2-2 (TGS-2), Page 1, Line (12
(4) Prorated for usage on and after November 1, 2024
(5) Prorated for usage prior to October 1, 2025
(6) Sum of revenue
(7) Line (1) + Line (6)

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

Attachment TGS-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2024 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2025 ISR Plan
For the Recovery/(Refund) Period October 1, 2025 through September 30, 2026

(1)	Actual FY 2025 O&M Revenue Requirement	$13,922,884
(2)	O&M Revenue Billed	$13,607,897
(3)	Total Over/(Under) Recovery for FY 2025	($314,987)
(4)	Remaining Over/(Under) For FY 2023	($14,693)
(5)	Total Over/(Under) Recovery	($329,680)
(6)	Forecasted kWhs - October 1, 2025 through September 30, 2026	7,664,288,774
(7)	Proposed O&M Reconciling Factor Charge/(Credit) per kWh	$0.00004

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

Fiscal Year 2024 Operations & Maintenance Reconciliation
For the Period April 1, 2024 through March 31, 2025
For the Recovery/Refund Period October 1, 2025 through September 30, 2026

O&M Factor Revenue:

	Month	O&M Revenue	Prior Period Reconciliation Factor Revenue	Base O&M Revenue
		(a)	(b)	(c)
(1)	Apr-24	$469,999	$37,382	$432,617
	May-24	$1,026,282	$85,172	$941,110
	Jun-24	$1,165,809	$95,885	$1,069,924
	Jul-24	$1,526,426	$121,284	$1,405,142
	Aug-24	$1,759,827	$134,192	$1,625,635
	Sep-24	$1,287,418	$102,229	$1,185,189
	Oct-24	$1,053,649	$82,721	$970,928
	Nov-24	$935,952	$61,158	$874,794
	Dec-24	$1,181,300	$61,951	$1,119,349
	Jan-25	$1,340,915	$64,574	$1,276,341
	Feb-25	$1,108,604	$52,175	$1,056,429
	Mar-25	$1,114,129	$54,128	$1,060,001
(2)	Apr-25	$620,758	30,320	$590,438
	Total	$14,591,068	$983,171	$13,607,897

(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 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	758,026,361	$121,284
	Aug-24	838,698,935	$134,192
	Sep-24	638,931,556	$102,229
(4)	Oct-24	325,844,852	$52,135
(5)	Total	7,368,682,525	$1,178,990
(6)	Ending Over/(Under) Recovery		($14,693)

(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)

Fiscal Year 2024 O&M Reconciliation of Under Recovery
For the Period April 1, 2023 through March 31, 2024
For the Recovery/Refund Period October 1, 2024 through September 30, 2025

		Total
(1)	Over/(Under) Recovery	($808,366)
(2)	O&M Reconciling Factor - 10/2024	$0.00016
(3)	O&M Reconciling Factor - 11/2024	$0.00010

		Total kWhs (a)	Total Revenue (b)
(4)	Oct-24	191,163,487	$30,586
	Nov-24	442,777,573	$61,158
	Dec-24	619,513,073	$61,951
	Jan-25	645,735,567	$64,574
	Feb-25	521,754,911	$52,175
	Mar-25	541,276,717	$54,128
	Apr-25	491,481,277	$49,148
	May-25	502,645,852	$50,265
	Jun-25	570,418,938	$57,042
	Jul-25	-	$0
	Aug-25	-	$0
	Sep-25	-	$0
(5)	Oct-25	-	$0
(6)	Total	4,526,767,395	$481,027
(7)	Ending Over/(Under) Recovery		($327,339)

(1) Docket No. 22-53-EL, Attachment PUC 4-2-3 (TGS-3) page 1, line (5)
(2) Docket No. 22-53-EL, Attachment PUC 4-2-3 (TGS-3) page 4, line (2)
(3) Docket No. 22-53-EL, Attachment PUC 4-2-3 (TGS-3) page 1, line (9)
(4) Reflects kWhs consumed on and after October 1
(5) Reflects kWhs consumed prior to October 1
(6) Sum of kWhs & revenue
(7) Line (1) + Line (6)

(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, 2025				Proposed Rates Effective October 1, 2025				$ 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	$33.65	$15.10	$2.03	$50.78	$33.77	$15.10	$2.04	$50.91	$0.12	$0.00	$0.01	$0.13	0.2%	0.0%	0.0%	0.3%	30.1%
300	$54.76	$30.20	$3.54	$88.50	$55.00	$30.20	$3.55	$88.75	$0.24	$0.00	$0.01	$0.25	0.3%	0.0%	0.0%	0.3%	12.9%
400	$68.84	$40.27	$4.55	$113.66	$69.15	$40.27	$4.56	$113.98	$0.31	$0.00	$0.01	$0.32	0.3%	0.0%	0.0%	0.3%	11.6%
500	$82.91	$50.34	$5.55	$138.80	$83.31	$50.34	$5.57	$139.22	$0.40	$0.00	$0.02	$0.42	0.3%	0.0%	0.0%	0.3%	9.6%
600	$96.98	$60.41	$6.56	$163.95	$97.46	$60.41	$6.58	$164.45	$0.48	$0.00	$0.02	$0.50	0.3%	0.0%	0.0%	0.3%	7.7%
700	$111.06	$70.48	$7.56	$189.10	$111.61	$70.48	$7.59	$189.68	$0.55	$0.00	$0.03	$0.58	0.3%	0.0%	0.0%	0.3%	19.0%
1,200	$181.43	$120.82	$12.59	$314.84	$182.38	$120.82	$12.63	$315.83	$0.95	$0.00	$0.04	$0.99	0.3%	0.0%	0.0%	0.3%	6.8%
2,000	$294.02	$201.36	$20.64	$516.02	$295.60	$201.36	$20.71	$517.67	$1.58	$0.00	$0.07	$1.65	0.3%	0.0%	0.0%	0.3%	2.3%

			Rates Effective July 1, 2025	Proposed Rates Effective October 1, 2025	Line Item on Bill
			(s)	(t)	
(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		$5.75	$5.75	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge		$0.00223	$0.00223	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00010	$0.00004	
(7)	CapEx Factor Charge		$0.00832	$0.00832	
(8)	CapEx Reconciliation Factor		$0.00010	$0.00095	
(9)	Revenue Decoupling Adjustment Factor		($0.00272)	($0.00272)	
(10)	Pension Adjustment Factor		($0.00339)	($0.00339)	
(11)	Storm Fund Replenishment Factor		$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor		$0.00006	$0.00006	
(13)	Performance Incentive Factor		$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor		$0.00251	$0.00251	
(15)	LRS Adjustment Factor		$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge		$0.00656	$0.00656	Renewable Energy Distribution Charge
(17)	Net Metering Charge		$0.01457	$0.01457	
(18)	Base Transmission Charge		$0.04411	$0.04411	Transmission Charge
(19)	Transmission Adjustment Factor		$0.00300	$0.00300	
(20)	Transmission Uncollectible Factor		$0.00062	$0.00062	
(21)	Base Transition Charge		$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment		$0.00001	$0.00001	
(23)	Energy Efficiency Program Charge		$0.01098	$0.01098	Energy Efficiency Programs
(24)	Last Resort Service Base Charge		$0.08706	$0.08706	Supply Services Energy Charge
(25)	LRS Adjustment Factor		($0.00355)	($0.00355)	
(26)	LRS Adminstrative Cost Adjustment Factor		$0.00256	$0.00256	
(27)	Renewable Energy Standard Charge		$0.01461	$0.01461	
	Line Item on Bill				
(28)	Customer Charge		$6.00	$6.00	
(29)	LIHEAP Enhancement Charge		$0.79	$0.79	
(30)	RE Growth Program		$5.75	$5.75	
(31)	Transmission Charge	kWh x	$0.04773	$0.04773	
(32)	Distribution Energy Charge	kWh x	$0.06089	$0.06168	
(33)	Transition Charge	kWh x	$0.00001	$0.00001	
(34)	Energy Efficiency Programs	kWh x	$0.01098	$0.01098	
(35)	Renewable Energy Distribution Charge	kWh x	$0.02113	$0.02113	
(36)	Supply Services Energy Charge	kWh x	$0.10068	$0.10068	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025

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 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025						Proposed Rates Effective October 1, 2025						$ 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	$33.27	$15.10	($12.09)	$36.28	$1.51	$37.79	$33.39	$15.10	($12.12)	$36.37	$1.52	$37.89	$0.09	$0.00	$0.01	$0.10	0.2%	0.0%	0.0%	0.3%	32.1%
300	$54.01	$30.20	($21.05)	$63.16	$2.63	$65.79	$54.25	$30.20	($21.11)	$63.34	$2.64	$65.98	$0.18	$0.00	$0.01	$0.19	0.3%	0.0%	0.0%	0.3%	15.4%
400	$67.83	$40.27	($27.03)	$81.07	$3.38	$84.45	$68.15	$40.27	($27.11)	$81.31	$3.39	$84.70	$0.24	$0.00	$0.01	$0.25	0.3%	0.0%	0.0%	0.3%	12.5%
500	$81.66	$50.34	($33.00)	$99.00	$4.13	$103.13	$82.05	$50.34	($33.10)	$99.29	$4.14	$103.43	$0.29	$0.00	$0.01	$0.30	0.3%	0.0%	0.0%	0.3%	9.6%
600	$95.48	$60.41	($38.97)	$116.92	$4.87	$121.79	$95.95	$60.41	($39.09)	$117.27	$4.89	$122.16	$0.35	$0.00	$0.02	$0.37	0.3%	0.0%	0.0%	0.3%	7.2%
700	$109.30	$70.48	($44.95)	$134.83	$5.62	$140.45	$109.85	$70.48	($45.08)	$135.25	$5.64	$140.89	$0.42	$0.00	$0.02	$0.44	0.3%	0.0%	0.0%	0.3%	16.4%
1,200	$178.42	$120.82	($74.81)	$224.43	$9.35	$233.78	$179.36	$120.82	($75.05)	$225.13	$9.38	$234.51	$0.70	$0.00	$0.03	$0.73	0.3%	0.0%	0.0%	0.3%	5.2%
2,000	$289.00	$201.36	($122.59)	$367.77	$15.32	$383.09	$290.58	$201.36	($122.99)	$368.95	$15.37	$384.32	$1.18	$0.00	$0.05	$1.23	0.3%	0.0%	0.0%	0.3%	1.6%

		Rates Effective July 1, 2025	Proposed Rates Effective October 1, 2025	Line Item on Bill
		(w)	(x)	
(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	$5.75	$5.75	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge	$0.00223	$0.00223	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00010	$0.00004	
(7)	CapEx Factor Charge	$0.00832	$0.00832	
(8)	CapEx Reconciliation Factor	$0.00010	$0.00095	
(9)	Revenue Decoupling Adjustment Factor	($0.00272)	($0.00272)	
(10)	Pension Adjustment Factor	($0.00339)	($0.00339)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(13)	Performance Incentive Factor	$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	LRS Adjustment Factor	$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00656	$0.00656	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.01457	$0.01457	
(18)	Base Transmission Charge	$0.04411	$0.04411	Transmission Charge
(19)	Transmission Adjustment Factor	$0.00300	$0.00300	
(20)	Transmission Uncollectible Factor	$0.00062	$0.00062	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00001	$0.00001	
(23)	Energy Efficiency Program Charge	$0.01098	$0.01098	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08706	$0.08706	Supply Services Energy Charge
(25)	LRS Adjustment Factor	($0.00355)	($0.00355)	
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00256	$0.00256	
(27)	Renewable Energy Standard Charge	$0.01461	$0.01461	
	Line Item on Bill			
(28)	Customer Charge	$6.00	$6.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$5.75	$5.75	
(31)	Transmission Charge	$0.04773	$0.04773	
(32)	Distribution Energy Charge	$0.05838	$0.05917	
(33)	Transition Charge	$0.00001	$0.00001	
(34)	Energy Efficiency Programs	$0.01098	$0.01098	
(35)	Renewable Energy Distribution Charge	$0.02113	$0.02113	
(36)	Supply Services Energy Charge	$0.10068	$0.10068	
(37)	Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025
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 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025						Proposed Rates Effective October 1, 2025						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total (e) = (b) + (c) + (d)	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total (k) = (h) + (i) + (j)	GET	Total	Delivery Services (n) = [(h)+(j)] - [(b)+(d)]	Supply Services	GET	Total (q) = (n) + (o) + (p)	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d) = [(b)+(c)] x-.30		(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30		(l)	(m) = (k) + (l)		(o) = (i) - (c)	(p) = (l) - (f)		(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$33.27	$15.10	($14.51)	$33.86	$1.41	$35.27	$33.39	$15.10	($14.55)	$33.94	$1.41	$35.35	$0.08	$0.00	$0.00	$0.08	0.2%	0.0%	0.0%	0.2%	32.1%
300	$54.01	$30.20	($25.26)	$58.95	$2.46	$61.41	$54.25	$30.20	($25.34)	$59.11	$2.46	$61.57	$0.16	$0.00	$0.00	$0.16	0.3%	0.0%	0.0%	0.3%	15.4%
400	$67.83	$40.27	($32.43)	$75.67	$3.15	$78.82	$68.15	$40.27	($32.53)	$75.89	$3.16	$79.05	$0.22	$0.00	$0.01	$0.23	0.3%	0.0%	0.0%	0.3%	12.5%
500	$81.66	$50.34	($39.60)	$92.40	$3.85	$96.25	$82.05	$50.34	($39.72)	$92.67	$3.86	$96.53	$0.27	$0.00	$0.01	$0.28	0.3%	0.0%	0.0%	0.3%	9.6%
600	$95.48	$60.41	($46.77)	$109.12	$4.55	$113.67	$95.95	$60.41	($46.91)	$109.45	$4.56	$114.01	$0.33	$0.00	$0.01	$0.34	0.3%	0.0%	0.0%	0.3%	7.2%
700	$109.30	$70.48	($53.93)	$125.85	$5.24	$131.09	$109.85	$70.48	($54.10)	$126.23	$5.26	$131.49	$0.38	$0.00	$0.02	$0.40	0.3%	0.0%	0.0%	0.3%	16.4%
1,200	$178.42	$120.82	($89.77)	$209.47	$8.73	$218.20	$179.36	$120.82	($90.05)	$210.13	$8.76	$218.89	$0.66	$0.00	$0.03	$0.69	0.3%	0.0%	0.0%	0.3%	5.2%
2,000	$289.00	$201.36	($147.11)	$343.25	$14.30	$357.55	$290.58	$201.36	($147.58)	$344.36	$14.35	$358.71	$1.11	$0.00	$0.05	$1.16	0.3%	0.0%	0.0%	0.3%	1.6%

		Rates Effective July 1, 2025	Proposed Rates Effective October 1, 2025	Line Item on Bill
		(w)	(x)	
(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	$5.75	$5.75	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge	$0.00223	$0.00223	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00010	$0.00004	
(7)	CapEx Factor Charge	$0.00832	$0.00832	
(8)	CapEx Reconciliation Factor	$0.00010	$0.00095	
(9)	Revenue Decoupling Adjustment Factor	($0.00272)	($0.00272)	
(10)	Pension Adjustment Factor	($0.00339)	($0.00339)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(13)	Performance Incentive Factor	$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	LRS Adjustment Factor	$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00656	$0.00656	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.01457	$0.01457	
(18)	Base Transmission Charge	$0.04411	$0.04411	Transmission Charge
(19)	Transmission Adjustment Factor	$0.00300	$0.00300	
(20)	Transmission Uncollectible Factor	$0.00062	$0.00062	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00001	$0.00001	
(23)	Energy Efficiency Program Charge	$0.01098	$0.01098	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08706	$0.08706	Supply Services Energy Charge
(25)	LRS Adjustment Factor	($0.00355)	($0.00355)	
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00256	$0.00256	
(27)	Renewable Energy Standard Charge	$0.01461	$0.01461	
	Line Item on Bill			
(28)	Customer Charge	$6.00	$6.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$5.75	$5.75	
(31)	Transmission Charge	$0.04773	$0.04773	
(32)	Distribution Energy Charge	$0.05838	$0.05917	
(33)	Transition Charge	$0.00001	$0.00001	
(34)	Energy Efficiency Programs	$0.01098	$0.01098	
(35)	Renewable Energy Distribution Charge	$0.02113	$0.02113	
(36)	Supply Services Energy Charge	$0.10068	$0.10068	
(37)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025

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 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025				Proposed Rates Effective October 1, 2025				$ 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)
250	$50.32	$23.95	$3.09	$77.36	$50.45	$23.95	$3.10	$77.50	$0.13	$0.00	$0.01	$0.14	0.2%	0.0%	0.0%	0.2%	56.3%
500	$81.08	$47.90	$5.37	$134.35	$81.33	$47.90	$5.38	$134.61	$0.25	$0.00	$0.01	$0.26	0.2%	0.0%	0.0%	0.2%	16.9%
1,000	$142.60	$95.79	$9.93	$248.32	$143.10	$95.79	$9.95	$248.84	$0.50	$0.00	$0.02	$0.52	0.2%	0.0%	0.0%	0.2%	8.1%
1,500	$204.12	$143.69	$14.49	$362.30	$204.87	$143.69	$14.52	$363.08	$0.75	$0.00	$0.03	$0.78	0.2%	0.0%	0.0%	0.2%	5.0%
2,000	$265.64	$191.58	$19.05	$476.27	$266.64	$191.58	$19.09	$477.31	$1.00	$0.00	$0.04	$1.04	0.2%	0.0%	0.0%	0.2%	13.6%

		Rates Effective July 1, 2025 (s)	Proposed Rates Effective October 1, 2025 (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	$8.77	$8.77	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04482	$0.04482	
(5)	Operating & Maintenance Expense Charge	$0.00219	$0.00219	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00010	$0.00004	
(7)	CapEx Factor Charge	$0.00694	$0.00694	
(8)	CapEx Reconciliation Factor	$0.00074	$0.00130	
(9)	Revenue Decoupling Adjustment Factor	($0.00272)	($0.00272)	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	$0.00000	$0.00000	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00656	$0.00656	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.01457	$0.01457	
(18)	Base Transmission Charge	$0.03042	$0.03042	
(19)	Transmission Adjustment Factor	$0.00009	$0.00009	Transmission Charge
(20)	Transmission Uncollectible Factor	$0.00034	$0.00034	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00001	$0.00001	
(23)	Energy Efficiency Program Charge	$0.01098	$0.01098	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08411	$0.08411	
(25)	LRS Adjustment Factor	($0.00600)	($0.00600)	Supply Services Energy Charge
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00307	$0.00307	
(27)	Renewable Energy Standard Charge	$0.01461	$0.01461	
	Line Item on Bill			
(28)	Customer Charge	$10.00	$10.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$8.77	$8.77	
(31)	Transmission Charge	$0.03085	$0.03085	
(32)	Distribution Energy Charge	$0.06007	$0.06057	
(33)	Transition Charge	$0.00001	$0.00001	
(34)	Energy Efficiency Programs	$0.01098	$0.01098	
(35)	Renewable Energy Distribution Charge	$0.02113	$0.02113	
(36)	Supply Services Energy Charge	$0.09579	$0.09579	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025

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 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025				Proposed Rates Effective October 1, 2025				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)
20	200	4,000	$671.05	$383.16	$43.93	$1,098.14	$673.49	$383.16	$44.03	$1,100.68	$2.44	$0.00	$0.10	$2.54	0.2%	0.0%	0.0%	0.2%
50	200	10,000	$1,460.77	$957.90	$100.78	$2,519.45	$1,466.87	$957.90	$101.03	$2,525.80	$6.10	$0.00	$0.25	$6.35	0.2%	0.0%	0.0%	0.3%
100	200	20,000	$2,776.97	$1,915.80	$195.53	$4,888.30	$2,789.17	$1,915.80	$196.04	$4,901.01	$12.20	$0.00	$0.51	$12.71	0.2%	0.0%	0.0%	0.3%
150	200	30,000	$4,093.17	$2,873.70	$290.29	$7,257.16	$4,111.47	$2,873.70	$291.05	$7,276.22	$18.30	$0.00	$0.76	$19.06	0.3%	0.0%	0.0%	0.3%
20	300	6,000	$779.09	$574.74	$56.41	$1,410.24	$782.75	$574.74	$56.56	$1,414.05	$3.66	$0.00	$0.15	$3.81	0.3%	0.0%	0.0%	0.3%
50	300	15,000	$1,730.87	$1,436.85	$131.99	$3,299.71	$1,740.02	$1,436.85	$132.37	$3,309.24	$9.15	$0.00	$0.38	$9.53	0.3%	0.0%	0.0%	0.3%
100	300	30,000	$3,317.17	$2,873.70	$257.95	$6,448.82	$3,335.47	$2,873.70	$258.72	$6,467.89	$18.30	$0.00	$0.77	$19.07	0.3%	0.0%	0.0%	0.3%
150	300	45,000	$4,903.47	$4,310.55	$383.92	$9,597.94	$4,930.92	$4,310.55	$385.06	$9,626.53	$27.45	$0.00	$1.14	$28.59	0.3%	0.0%	0.0%	0.3%
20	400	8,000	$887.13	$766.32	$68.89	$1,722.34	$892.01	$766.32	$69.10	$1,727.43	$4.88	$0.00	$0.21	$5.09	0.3%	0.0%	0.0%	0.3%
50	400	20,000	$2,000.97	$1,915.80	$163.20	$4,079.97	$2,013.17	$1,915.80	$163.71	$4,092.68	$12.20	$0.00	$0.51	$12.71	0.3%	0.0%	0.0%	0.3%
100	400	40,000	$3,857.37	$3,831.60	$320.37	$8,009.34	$3,881.77	$3,831.60	$321.39	$8,034.76	$24.40	$0.00	$1.02	$25.42	0.3%	0.0%	0.0%	0.3%
150	400	60,000	$5,713.77	$5,747.40	$477.55	$11,938.72	$5,750.37	$5,747.40	$479.07	$11,976.84	$36.60	$0.00	$1.52	$38.12	0.3%	0.0%	0.0%	0.3%
20	500	10,000	$995.17	$957.90	$81.38	$2,034.45	$1,001.27	$957.90	$81.63	$2,040.80	$6.10	$0.00	$0.25	$6.35	0.3%	0.0%	0.0%	0.3%
50	500	25,000	$2,271.07	$2,394.75	$194.41	$4,860.23	$2,286.32	$2,394.75	$195.04	$4,876.11	$15.25	$0.00	$0.63	$15.88	0.3%	0.0%	0.0%	0.3%
100	500	50,000	$4,397.57	$4,789.50	$382.79	$9,569.86	$4,428.07	$4,789.50	$384.07	$9,601.64	$30.50	$0.00	$1.28	$31.78	0.3%	0.0%	0.0%	0.3%
150	500	75,000	$6,524.07	$7,184.25	$571.18	$14,279.50	$6,569.82	$7,184.25	$573.09	$14,327.16	$45.75	$0.00	$1.91	$47.66	0.3%	0.0%	0.0%	0.3%
20	600	12,000	$1,103.21	$1,149.48	$93.86	$2,346.55	$1,110.53	$1,149.48	$94.17	$2,354.18	$7.32	$0.00	$0.31	$7.63	0.3%	0.0%	0.0%	0.3%
50	600	30,000	$2,541.17	$2,873.70	$225.62	$5,640.49	$2,559.47	$2,873.70	$226.38	$5,659.55	$18.30	$0.00	$0.76	$19.06	0.3%	0.0%	0.0%	0.3%
100	600	60,000	$4,937.77	$5,747.40	$445.22	$11,130.39	$4,974.37	$5,747.40	$446.74	$11,168.51	$36.60	$0.00	$1.52	$38.12	0.3%	0.0%	0.0%	0.3%
150	600	90,000	$7,334.37	$8,621.10	$664.81	$16,620.28	$7,389.27	$8,621.10	$667.10	$16,677.47	$54.90	$0.00	$2.29	$57.19	0.3%	0.0%	0.0%	0.3%

		Rates Effective July 1, 2025 (r)	Proposed Rates Effective October 1, 2025 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$91.08	$91.08	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)	$2.33	$2.33	
(6)	Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00205	$0.00205	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00010	$0.00004	
(9)	CapEx Reconciliation Factor	($0.00032)	$0.00035	
(10)	Revenue Decoupling Adjustment Factor	($0.00272)	($0.00272)	
(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	$0.00000	$0.00000	
(17)	Long-term Contracting for Renewable Energy Charge	$0.00656	$0.00656	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.01457	$0.01457	
(19)	Transmission Demand Charge	$6.29	$6.29	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01187	$0.01187	Transmission Adjustment
(21)	Transmission Adjustment Factor	($0.00226)	($0.00226)	
(22)	Transmission Uncollectible Factor	$0.00042	$0.00042	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00001	$0.00001	
(25)	Energy Efficiency Program Charge	$0.01098	$0.01098	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.08411	$0.08411	Supply Services Energy Charge
(27)	LRS Adjustment Factor	($0.00600)	($0.00600)	
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00307	$0.00307	
(29)	Renewable Energy Standard Charge	$0.01461	$0.01461	
	Line Item on Bill			
(30)	Customer Charge	$145.00	$145.00	
(32)	LIHEAP Enhancement Charge	$0.79	$0.79	
(31)	RE Growth Program	$91.08	$91.08	
(33)	Transmission Adjustment	$0.01003	$0.01003	
(34)	Distribution Energy Charge	$0.01187	$0.01248	
(35)	Distribution Demand Charge	$9.23	$9.23	
(36)	Transmission Demand Charge	$6.29	$6.29	
(35)	Transition Charge	$0.00001	$0.00001	
(36)	Energy Efficiency Programs	$0.01098	$0.01098	
(37)	Renewable Energy Distribution Charge	$0.02113	$0.02113	
(38)	Supply Services Energy Charge	$0.09579	$0.09579	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025
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 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025				Proposed Rates Effective October 1, 2025				$ 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	$5,808.75	$5,596.67	$475.23	$11,880.65	$5,831.95	$5,596.67	$476.19	$11,904.81	$23.20	$0.00	$0.96	$24.16	0.2%	0.0%	0.0%	0.2%
750	200	150,000	$20,883.15	$20,987.50	$1,744.61	$43,615.26	$20,970.15	$20,987.50	$1,748.24	$43,705.89	$87.00	$0.00	$3.63	$90.63	0.2%	0.0%	0.0%	0.2%
1,000	200	200,000	$27,735.15	$27,983.33	$2,321.60	$58,040.08	$27,851.15	$27,983.33	$2,326.44	$58,160.92	$116.00	$0.00	$4.84	$120.84	0.2%	0.0%	0.0%	0.2%
1,500	200	300,000	$41,439.15	$41,975.00	$3,475.59	$86,889.74	$41,613.15	$41,975.00	$3,482.84	$87,070.99	$174.00	$0.00	$7.25	$181.25	0.2%	0.0%	0.0%	0.2%
2,500	200	500,000	$68,847.15	$69,958.33	$5,783.56	$144,589.04	$69,137.15	$69,958.33	$5,795.65	$144,891.13	$290.00	$0.00	$12.09	$302.09	0.2%	0.0%	0.0%	0.2%
5,000	200	1,000,000	$137,367.15	$139,916.67	$11,553.49	$288,837.31	$137,947.15	$139,916.67	$11,577.66	$289,441.48	$580.00	$0.00	$24.17	$604.17	0.2%	0.0%	0.0%	0.2%
7,500	200	1,500,000	$205,887.15	$209,875.00	$17,323.42	$433,085.57	$206,757.15	$209,875.00	$17,359.67	$433,991.82	$870.00	$0.00	$36.25	$906.25	0.2%	0.0%	0.0%	0.2%
10,000	200	2,000,000	$274,407.15	$279,833.33	$23,093.36	$577,333.84	$275,567.15	$279,833.33	$23,141.69	$578,542.17	$1,160.00	$0.00	$48.33	$1,208.33	0.2%	0.0%	0.0%	0.2%
20,000	200	4,000,000	$548,487.15	$559,666.67	$46,173.08	$1,154,326.90	$550,807.15	$559,666.67	$46,269.75	$1,156,743.57	$2,320.00	$0.00	$96.67	$2,416.67	0.2%	0.0%	0.0%	0.2%
200	300	60,000	$7,026.55	$8,395.00	$642.56	$16,064.11	$7,061.35	$8,395.00	$644.01	$16,100.36	$34.80	$0.00	$1.45	$36.25	0.2%	0.0%	0.0%	0.2%
750	300	225,000	$25,449.90	$31,481.25	$2,372.13	$59,303.28	$25,580.40	$31,481.25	$2,377.57	$59,439.22	$130.50	$0.00	$5.44	$135.94	0.2%	0.0%	0.0%	0.2%
1,000	300	300,000	$33,824.15	$41,975.00	$3,158.30	$78,957.45	$33,998.15	$41,975.00	$3,165.55	$79,138.70	$174.00	$0.00	$7.25	$181.25	0.2%	0.0%	0.0%	0.2%
1,500	300	450,000	$50,572.65	$62,962.50	$4,730.63	$118,265.78	$50,833.65	$62,962.50	$4,741.51	$118,537.66	$261.00	$0.00	$10.88	$271.88	0.2%	0.0%	0.0%	0.2%
2,500	300	750,000	$84,069.65	$104,937.50	$7,875.30	$196,882.45	$84,504.65	$104,937.50	$7,893.42	$197,335.57	$435.00	$0.00	$18.12	$453.12	0.2%	0.0%	0.0%	0.2%
5,000	300	1,500,000	$167,812.15	$209,875.00	$15,736.97	$393,424.12	$168,682.15	$209,875.00	$15,773.22	$394,330.37	$870.00	$0.00	$36.25	$906.25	0.2%	0.0%	0.0%	0.2%
7,500	300	2,250,000	$251,554.65	$314,812.50	$23,598.63	$589,965.78	$252,859.65	$314,812.50	$23,653.01	$591,325.16	$1,305.00	$0.00	$54.38	$1,359.38	0.2%	0.0%	0.0%	0.2%
10,000	300	3,000,000	$335,297.15	$419,750.00	$31,460.30	$786,507.45	$337,037.15	$419,750.00	$31,532.80	$788,319.95	$1,740.00	$0.00	$72.50	$1,812.50	0.2%	0.0%	0.0%	0.2%
20,000	300	6,000,000	$670,267.15	$839,500.00	$62,906.97	$1,572,674.12	$673,747.15	$839,500.00	$63,051.97	$1,576,299.12	$3,480.00	$0.00	$145.00	$3,625.00	0.2%	0.0%	0.0%	0.2%
200	400	80,000	$8,244.35	$11,193.33	$809.90	$20,247.58	$8,290.75	$11,193.33	$811.84	$20,295.92	$46.40	$0.00	$1.94	$48.34	0.2%	0.0%	0.0%	0.2%
750	400	300,000	$30,016.65	$41,975.00	$2,999.65	$74,991.30	$30,190.65	$41,975.00	$3,006.90	$75,172.55	$174.00	$0.00	$7.25	$181.25	0.2%	0.0%	0.0%	0.2%
1,000	400	400,000	$39,913.15	$55,966.67	$3,994.99	$99,874.81	$40,145.15	$55,966.67	$4,004.66	$100,116.48	$232.00	$0.00	$9.67	$241.67	0.2%	0.0%	0.0%	0.2%
1,500	400	600,000	$59,706.15	$83,950.00	$5,985.67	$149,641.82	$60,054.15	$83,950.00	$6,000.17	$150,004.32	$348.00	$0.00	$14.50	$362.50	0.2%	0.0%	0.0%	0.2%
2,500	400	1,000,000	$99,292.15	$139,916.67	$9,967.03	$249,175.85	$99,872.15	$139,916.67	$9,991.20	$249,780.02	$580.00	$0.00	$24.17	$604.17	0.2%	0.0%	0.0%	0.2%
5,000	400	2,000,000	$198,257.15	$279,833.33	$19,920.44	$498,010.92	$199,417.15	$279,833.33	$19,968.77	$499,219.25	$1,160.00	$0.00	$48.33	$1,208.33	0.2%	0.0%	0.0%	0.2%
7,500	400	3,000,000	$297,222.15	$419,750.00	$29,873.84	$746,845.99	$298,962.15	$419,750.00	$29,946.34	$748,658.49	$1,740.00	$0.00	$72.50	$1,812.50	0.2%	0.0%	0.0%	0.2%
10,000	400	4,000,000	$396,187.15	$559,666.67	$39,827.25	$995,681.07	$398,507.15	$559,666.67	$39,923.91	$998,097.73	$2,320.00	$0.00	$96.66	$2,416.66	0.2%	0.0%	0.0%	0.2%
20,000	400	8,000,000	$792,047.15	$1,119,333.33	$79,640.86	$1,991,021.34	$796,687.15	$1,119,333.33	$79,834.19	$1,995,854.67	$4,640.00	$0.00	$193.33	$4,833.33	0.2%	0.0%	0.0%	0.2%
200	500	100,000	$9,462.15	$13,991.67	$977.24	$24,431.06	$9,520.15	$13,991.67	$979.66	$24,491.48	$58.00	$0.00	$2.42	$60.42	0.2%	0.0%	0.0%	0.2%
750	500	375,000	$34,583.40	$52,468.75	$3,627.17	$90,679.32	$34,800.90	$52,468.75	$3,636.24	$90,905.89	$217.50	$0.00	$9.07	$226.57	0.2%	0.0%	0.0%	0.2%
1,000	500	500,000	$46,002.15	$69,958.33	$4,831.69	$120,792.17	$46,292.15	$69,958.33	$4,843.77	$121,094.25	$290.00	$0.00	$12.08	$302.08	0.2%	0.0%	0.0%	0.3%
1,500	500	750,000	$68,839.65	$104,937.50	$7,240.72	$181,017.87	$69,274.65	$104,937.50	$7,258.84	$181,470.99	$435.00	$0.00	$18.12	$453.12	0.2%	0.0%	0.0%	0.3%
2,500	500	1,250,000	$114,514.65	$174,895.83	$12,058.77	$301,469.25	$115,239.65	$174,895.83	$12,088.98	$302,224.46	$725.00	$0.00	$30.21	$755.21	0.2%	0.0%	0.0%	0.3%
5,000	500	2,500,000	$228,702.15	$349,791.67	$24,103.91	$602,597.73	$230,152.15	$349,791.67	$24,164.33	$604,108.15	$1,450.00	$0.00	$60.42	$1,510.42	0.2%	0.0%	0.0%	0.3%
7,500	500	3,750,000	$342,889.65	$524,687.50	$36,149.05	$903,726.20	$345,064.65	$524,687.50	$36,239.68	$905,991.83	$2,175.00	$0.00	$90.63	$2,265.63	0.2%	0.0%	0.0%	0.3%
10,000	500	5,000,000	$457,077.15	$699,583.33	$48,194.19	$1,204,854.67	$459,977.15	$699,583.33	$48,315.02	$1,207,875.50	$2,900.00	$0.00	$120.83	$3,020.83	0.2%	0.0%	0.0%	0.3%
20,000	500	10,000,000	$913,827.15	$1,399,166.67	$96,374.75	$2,409,368.57	$919,627.15	$1,399,166.67	$96,616.42	$2,415,410.24	$5,800.00	$0.00	$241.67	$6,041.67	0.2%	0.0%	0.0%	0.3%
200	600	120,000	$10,679.95	$16,790.00	$1,144.58	$28,614.53	$10,749.55	$16,790.00	$1,147.48	$28,687.03	$69.60	$0.00	$2.90	$72.50	0.2%	0.0%	0.0%	0.3%
750	600	450,000	$39,150.15	$62,962.50	$4,254.69	$106,367.34	$39,411.15	$62,962.50	$4,265.57	$106,639.22	$261.00	$0.00	$10.88	$271.88	0.2%	0.0%	0.0%	0.3%
1,000	600	600,000	$52,091.15	$83,950.00	$5,668.38	$141,709.53	$52,439.15	$83,950.00	$5,682.88	$142,072.03	$348.00	$0.00	$14.50	$362.50	0.2%	0.0%	0.0%	0.3%
1,500	600	900,000	$77,973.15	$125,925.00	$8,495.76	$212,393.91	$78,495.15	$125,925.00	$8,517.51	$212,937.66	$522.00	$0.00	$21.75	$543.75	0.2%	0.0%	0.0%	0.3%
2,500	600	1,500,000	$129,737.15	$209,875.00	$14,150.51	$353,762.66	$130,607.15	$209,875.00	$14,186.76	$354,668.91	$870.00	$0.00	$36.25	$906.25	0.2%	0.0%	0.0%	0.3%
5,000	600	3,000,000	$259,147.15	$419,750.00	$28,287.38	$707,184.53	$260,887.15	$419,750.00	$28,359.88	$708,997.03	$1,740.00	$0.00	$72.50	$1,812.50	0.2%	0.0%	0.0%	0.3%
7,500	600	4,500,000	$388,557.15	$629,625.00	$42,424.26	$1,060,606.41	$391,167.15	$629,625.00	$42,533.01	$1,063,325.16	$2,610.00	$0.00	$108.75	$2,718.75	0.2%	0.0%	0.0%	0.3%
10,000	600	6,000,000	$517,967.15	$839,500.00	$56,561.14	$1,414,028.29	$521,447.15	$839,500.00	$56,706.14	$1,417,653.29	$3,480.00	$0.00	$145.00	$3,625.00	0.2%	0.0%	0.0%	0.3%
20,000	600	12,000,000	$1,035,607.15	$1,679,000.00	$113,108.64	$2,827,715.79	$1,042,567.15	$1,679,000.00	$113,398.64	$2,834,965.79	$6,960.00	$0.00	$290.00	$7,250.00	0.2%	0.0%	0.0%	0.3%

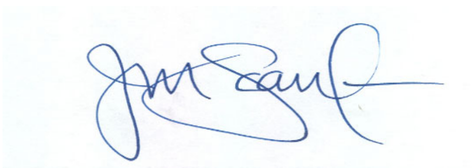
		Rates Effective July 1, 2025 (r)	Proposed Rates Effective October 1, 2025 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$758.36	$758.36	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 200kW)	$5.30	$5.30	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 200kW)	$2.36	$2.36	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00104	$0.00104	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00010	$0.00004	
(9)	CapEx Reconciliation Factor	($0.00038)	$0.00026	
(10)	Revenue Decoupling Adjustment Factor	($0.00272)	($0.00272)	
(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	$0.00656	$0.00656	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.01457	$0.01457	
(19)	Transmission Demand Charge	$7.57	$7.57	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01592	$0.01592	Transmission Adjustment
(21)	Transmission Adjustment Factor	$0.00200	$0.00200	
(22)	Transmission Uncollectible Factor	$0.00051	$0.00051	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00001	$0.00001	
(25)	Energy Efficiency Program Charge	$0.01098	$0.01098	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.11828	$0.11828	Supply Services Energy Charge
(27)	LRS Adjustment Factor	$0.00555	$0.00555	
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00148	$0.00148	
(29)	Renewable Energy Standard Charge	$0.01461	$0.01461	
	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	$758.36	$758.36	
(33)	Transmission Adjustment	$0.01843	$0.01843	
(34)	Distribution Energy Charge	$0.01034	$0.01092	
(35)	Distribution Demand Charge	$7.66	$7.66	
(36)	Transmission Demand Charge	$7.57	$7.57	
(35)	Transition Charge	$0.00001	$0.00001	
(36)	Energy Efficiency Programs	$0.01098	$0.01098	
(37)	Renewable Energy Distribution Charge	$0.02113	$0.02113	
(38)	Supply Services Energy Charge	$0.13992	$0.13992	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2025, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2025
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 7/1/2025, and Summary of Rates Last Res
Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2025.

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, 2025
Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
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