Rhode Island Energy

The Narragansett Electric Company

FY 2023 Electric Infrastructure, Safety and Reliability Plan

Annual Reconciliation

August 1, 2023

Docket No. 5209

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

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

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

Rhode Island Energy™
a PPL company

August 1, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 5209 - FY 2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

Dear Ms. Massaro:

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") 2023[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. 2199 (the "ISR Provision").

This Filing consists of the following documents:

- **Pre-Filed Direct Testimony of Nicole A. Gooding** – The testimony of Ms. Gooding presents the Filing in relation to the FY 2023 Electric ISR Plan which was approved by the PUC in this docket. Attachment NAG-1, which is attached to Ms. Gooding's testimony, includes an Executive Summary, FY 2023 Plant in Service Additions, FY 2023 Capital Spending Summary, FY 2023 Capital Spending by Key Driver Category, FY 2023 Vegetation Management ("VM"), FY 2023 Other Operations and Maintenance ("O&M"), and Reliability Performance. See below for summary:

Item	Target/Budget	Actual
Plant in Service Additions	$105.3M	$94.8M
Cost of Removal Spending	$16.3M	$7.8M
Capital Spending	$104.7M	$108.4M
O&M Spending	$13.1M	$13.7M

[1] FY 2023 was April 1, 2022 through March 31, 2023.

- **Joint Pre-Filed Direct Testimony of Stephanie A. Briggs, Jeffrey D. Oliveira and Natalie Hawk** – The joint testimony of Ms. Briggs, Mr. Oliveira and Ms. Hawk describes the calculation of the revenue requirement. The revenue requirement (net of the two adjustments described below) totals $40,031,046. This is a decrease of $9,690,279 from the projected FY 2023 Electric ISR revenue requirement of $49,721,324, previously approved by the PUC in this docket.

  In this case, the total capital investment component of the revenue requirement includes two adjustments. An adjustment of ($3,216,001) in connection with an ongoing review by the Company of distributed generation ("DG") projects. As described in Ms. Gooding's testimony, the Company removed plant additions associated with DG projects from the revenue requirement until a review of each DG project is completed. A second adjustment was made for the tax hold harmless impact on ISR rate base.[2] The testimony of Ms. Hawk provides details on the hold harmless adjustment which totaled ($759,233).

- **Pre-Filed Direct Testimony of Tyler G. Shields** – The testimony of Mr. Shields presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the ISR Provision, resulting from the reconciliation of actual costs and revenue associated with the FY 2023 ISR Plan. The impact of the proposed CapEx Reconciling Factor of ($0.00148) per kWh and the proposed O&M Reconciling Factor of $0.00016 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is a decrease of $0.23, or approximately 0.2%, from $134.24 to $134.01.

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. 5209 Service List

[2] 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.

<u>Certificate of Service</u>

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.

__________________________________ <u>August 1, 2023</u>
Joanne M. Scanlon Date

Docket No. 5209 – RI Energy's Electric ISR Plan FY 2024
Service List as of 8/1/2023

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

David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources Al Vitali, Esq.	Albert.vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Shauna.Beland@energy.ri.gov; Matthew.Moretta.CTR@energy.ri.gov;	
File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Esq. Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107
Matt Sullivan, Green Development LLC	ms@green-ri.com;	

PRE-FILED DIRECT TESTIMONY

OF

NICOLE A. GOODING

August 1, 2023

Table of Contents

I. Introduction and Qualifications

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

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

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

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

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

A. In 2017, I graduated from the University of South Carolina with a Bachelor of Science degree in International Business, Finance and Risk Management. In June 2017, I joined National Grid USA Service Company, Inc. ("NGSC") as an Associate Project Manager in the Gas Complex Capital Delivery department, progressing to a Project Manager in October 2018. I managed the execution of liquefied natural gas ("LNG"), regulator station and leak-prone pipe projects in Rhode Island and Massachusetts. In 2021, I moved to Goulston & Storrs as a Project Management Organization ("PMO") Specialist, working on implementing project management practices and policies across the business. I completed my Master of Business Administration degree in December 2021 from the College of William and Mary and Project Management Professional ("PMP") Certification in June 2022. I joined Rhode Island Energy in July of 2022 and assumed my role as ISR Manager.

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

A. Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2024 Electric Infrastructure, Safety and Reliability Plan in Docket 22-53-EL.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's FY 2023 Annual Reconciliation filing related to the FY 2023 Electric ISR Plan approved by the PUC in this docket. This filing provides the actual plant in service for discretionary and non-discretionary capital investment and associated cost of removal ("COR"), the actual vegetation management ("VM") operation and maintenance ("O&M") expenses, and the actual inspection and maintenance ("I&M") program and other O&M expenses for the period April 1, 2022, to March 31, 2023. As described in Ms. Stephanie Briggs', Mr. Jeffrey Oliveira's and Ms. Natalie Hawk's Joint Testimony in this filing, the plant in service investment and the O&M expenses are used to calculate the FY 2023 Electric ISR

Plan revenue requirement. As explained in Mr. Tyler Shields' testimony in this filing, the annual capital investment revenue requirement on the actual cumulative ISR capital investment and the actual O&M expense incurred is then reconciled against the actual revenue billed during FY 2023. Specific details by category for the FY 2023 Electric ISR Plan plant-in-service additions, associated COR, and actual capital spending are included in Attachment NAG-1, which is attached to this testimony.

III. Plant In Service and Cost of Removal

Q. Please provide an overview of the plant in service and cost of removal for FY 2023.

A. As shown in Table 2 of Attachment NAG-1, in FY 2023, plant additions of $94.8 million were placed in service. This amount was approximately $10.5 million under the target of $105.3 million. Non-Discretionary plant additions totaling $41.4 million were placed in service, which was $1.7 million under the target of $43.1 million. This variance was due to lower than expected plant additions for storms and the Westerly #2 Transformer project. Discretionary plant additions totaling $53.3 million were placed in service, which was $8.8 million under the planned amount of $62.1 million. This was primarily driven by lower actual capital spending than budgeted and the timing of spending between ISR fiscal years.

As shown in Table 3 of Attachment NAG-1, the associated cost of removal was $7.8 million which was under-budget by $8.5 million from the FY 2023 target of

$16.3 million. This was primarily due to the delay in demolition of the Pawtucket #1 Substation (Southeast Substation project) and Dyer St Substation projects. These totals resulted in an Electric ISR Plan investment of $102.6 million, which was $19.0 million under the Company's target of $121.6 million. Additional details on these variances are included in Section I of Attachment NAG-1.

IV. Capital Spending

Q. Please summarize the Company's actual capital spending for FY 2023 for the Electric ISR Plan.

A. As shown in Table 4 of Attachment NAG-1, the Company spent $108.4 million for capital investment under the Electric ISR Plan. This amount was $3.7 million over the annual approved budget of $104.8 million.

Non-discretionary capital spending was $49.2 million, which was $7.8 million over the annual approved budget of $41.4 million. This was primarily driven by spending on Distributed Generation, New Business work and Damage/Failure spending.

For FY 2023, capital spending in the Discretionary sub-category (excluding large projects) was $37.6 million, which was $1.9 million over the annual approved budget of $35.7 million. This was driven primarily by the fencing for the South St project as well as increased work completed on the Underground Residential Development ("URD") program.

In FY 2023, the Southeast Substation, Dyer Street Substation, Providence Study, East Providence Substation, Warren Substation and Tiverton Substation projects were reported on separately from other Asset Condition and System Capacity & Performance projects. Capital spending was $21.7 million, which was $5.9 million under the annual approved budget of $27.6 million. The Company experienced longer than anticipated lead times on materials which impacted the majority of Large Projects.

The key drivers and variances by category are discussed in more detail in Section III of Attachment NAG-1.

V. O&M Spending

Q. Please summarize the Company's actual O&M spending for the FY 2023 Electric ISR Plan.

A. Total O&M spending was $13.7 million as compared to a budget of $13.1 million. As shown in Table 10 of Attachment NAG-1, for FY 2023, the Company's vegetation management O&M spending was $12.7 million, which was over-budget by $.9 million. Cycle trimming along the 85T1 feeder in Westerly and Hopkinton was advanced into the 2023 ISR Plan Year to reduce tree-related outages.

In addition, as shown in Table 11, the Company's Other O&M spending related to the I&M and Volt/VAR Optimization and Conservations Voltage Reduction ("VVO/CVR") programs was $1.0 million, which was $.3 million under the approved O&M budget of $1.3 million. Detailed information regarding the work completed is discussed in Attachment NAG-1 in Section IV and Section V, respectively.

VI. Reliability Performance

Q. Please summarize the results of the Company's reliability performance for CY 2022.

A. Section VI of Attachment NAG-1 includes the Company's Reliability Performance for calendar year 2022 (CY 2022). The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2022, with SAIFI of .866 against a target of 1.05, and SAIDI of 62.48 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[1]

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

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

A. As stated in the March 9, 2022, hearing, the Company undertook a review of DG projects including the allocation of capital contributions to projects by cost type, the identification of cost variance drivers, and the processes that support these items.

The Company reviewed $4.9 million in plant additions and determined that $1.2 million will remain in rate base. These plant additions represent system improvements or projects where the actual costs exceeded the estimate, and the difference could not be collected from the customer.

The remaining plant additions of $3.6 million that were reviewed will be expensed. Based on a preliminary analysis, these projects fell into two categories (1) CIACs were incorrectly applied to the cost types and (2) the reconciliation process led to the customers receiving a refund. The Company is in the process of reviewing these projects and validating assumptions with National Grid.

From this review, the Company has decided to remove the remaining plant additions associated with DG projects from the revenue requirement until a review of each project is completed, totaling $10.6 million. The Company is anticipating any plant additions associated with the review will be incorporated into the ISR FY 2024 Annual Reconciliation.

The Company has also made process changes moving forward. The Company will now not place a project into service until it has been fully reconciled. There is also increased communication between the execution teams and the Customer Energy Integration "CEI" team on project status and potential cost overruns.

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

A. The Company has written off $0.855 million of the Dyer Street project costs related to the preconstruction costs for the DC building. Once the entire project is complete, the Company will again review all costs to ensure spending related to the refurbishment of the DC building is not included in ISR rate base and revenue requirements.

Q. Please summarize the drivers related to the recloser projects, work performed during the 2023 ISR year and the amount of plant placed into service.

A. Rhode Island Energy progressed with recloser installations with the purpose of improving reliability. Frequent circuit interruptions (approximately one interruption every third day during blue sky conditions) and low numbers of reclosers per circuit were identified during the summer of 2022. The installation of these pole-top reclosers allows for feeder sectionalization during fault conditions and minimizes the number of customers interrupted.[2] The Company installed reclosers under the reliability blanket during ISR

[2] Or increases the customers restored in less than 5 minutes.

Year 2023. Reclosers, with a cost of approximately $80,000, have been installed under the reliability blanket for past approved and reconciled ISR plans and that practice was continued for the 2023 ISR year. While this led to an overspend in the reliability blanket of $1.4 million, 19,344 customer interruptions have been saved from the installation of these reclosers since December 2022.

With current supply chain conditions and the volume of reclosers identified as needed, the Company realized that engineering and procurement would need to begin during the 2023 ISR Year if installations were going to take place in 2024. The Company spent $1.7 million in ISR Year 2023 under the Mainline Recloser Enhancement program for planning, engineering, and procurement. There are no plant additions associated with this spending. The Company is continuing discussions with the Division on the need for reclosers and anticipates including a revised proposal in the ISR Year 2025 Plan.

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

A. In August 2022, the metal clad switchgear at the Nasonville Substation was damaged beyond repair due to a feeder fault. The failed switchgear will be replaced with an open-air straight bus that will include a main breaker, capacitor breaker, and three feeder breakers. This replacement bus will initially be supplied by the existing transmission line and existing transformer. Removal of the failed equipment, design, engineering, and procurement of long lead time materials for the replacement began immediately and will be completed by the spring of 2024.

Regarding the area study work that commenced in ISR Year 2024, the station will be expanded with a new four breaker bus as recommended in the Northwest Rhode Island Area Study. The substation expansion will be an open-air design, with a new transformer to be placed on order shortly. Due to the lead time of the transformer, this phase of the project will take several years to complete. This is aligned with the recommended option in that it addresses the contingency loading issues that were identified at the time of the completion of the area study.

Q. The Company anticipated that the Westerly #2 spare transformer would be received this year. Why was it not received and when is receipt anticipated?

A. The Westerly #2 spare transformer initially was going to be received in the spring of 2023; however, the delivery date has been pushed until June 2024 due to supply chain constraints.

Q. Please provide an update on supply chain issues.

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

Q. Does this conclude your testimony?

A. Yes.

Attachment NAG-1

FY 2023 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing

Fiscal Year 2023 Electric Infrastructure, Safety, and Reliability Plan Annual Reconciliation Filing

EXECUTIVE SUMMARY

In accordance with its tariff, RIPUC No. 2199, Sheets 1-5, The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") submits this Annual Reconciliation Filing for the period April 1, 2022, through March 31, 2023 ("ISR Plan Fiscal Year 2023" or "2023") for the Electric Infrastructure, Safety, and Reliability Plan approved by the Rhode Island Public Utilities Commission ("PUC") in Docket No. 5209. This filing provides the actual capital spending and operation and maintenance ("O&M") spending for the ISR Plan Fiscal Year 2023. In addition, actual Plant in Service Additions and Cost of Removal spending are compared to targets for discretionary and non-discretionary categories. Finally, this filing includes a summary of the Company's reliability performance for the calendar year ("CY") ending December 31, 2022. Table 1 summarizes the 2023 program.

Table 1
2023 ISR Plan Activity

in millions $	Target / Budget	Actuals	Variance Over / (Under)
Plant in Service Additions - Non-discretionary	$43.1	$41.4	($1.7)
Plant in Service Additions - Discretionary	$62.1	$53.3	($8.8)
Plant in Service Additions	**$105.3**	**$94.8**	**($10.5)**
Cost of Removal Spending - Non-discretionary	$4.4	$4.6	$0.1
Cost of Removal Spending - Discretionary	$11.9	$3.2	($8.7)
Cost of Removal Spending	**$16.3**	**$7.8**	**($8.5)**
Capital Spending - Non-discretionary	$41.4	$49.2	$7.8
Capital Spending - Discretionary	$63.3	$59.3	($4.1)
Capital Spending	**$104.7**	**$108.4**	**$3.7**
Vegetation Management Spending	$11.9	$12.7	$0.9
I&M and Other O&M Spending	$1.3	$1.0	($0.3)
O&M Spending	**$13.1**	**$13.7**	**$0.6**

This filing includes testimony from Ms. Briggs, Mr. Oliveira, Ms. Hawk and Mr. Shields. Ms. Briggs', Mr. Oliveira's, and Ms. Hawk's joint 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. Their testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. In addition, their testimony describes a downward adjustment totaling $759,233 that was made for the tax hold harmless impact on ISR rate base.[1] As shown in Ms. Briggs', Mr. Oliveira's, and Ms. Hawk's joint testimony, for the ISR Plan Fiscal Year 2023 filing, the Company has an updated revenue requirement of $40.0 million.

Mr. Shields' testimony provides a description of the reconciliation of the final actual 2023 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 a decrease of $0.23, or approximately 0.2% from $134.24 to $134.01.

I. ISR Plan Fiscal Year 2023 Plant in Service Additions

As shown in Table 2 below, plant additions of $94.8 million were placed in service, $10.5 million under the target amount of $105.3 million. Non-discretionary plant additions of $41.4 million were placed in service, $1.7 million under the target of $43.1 million. Actual plant additions related to customer driven work were above the target. These were offset by no additions related to the Westerly #2 spare transformer because the delivery of the transformer was delayed, and there were fewer plant additions related to storms because of a lower level of storms capital spending. Discretionary plant additions of $53.3 million were placed in service, $8.8 million under the planned amount of $62.2 million. The primary reasons for fewer plant additions were lower actual capital spending than budgeted and the timing of spending between ISR plan fiscal years.

[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

	Target	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$27,143,209	$27,984,205	$840,995
Damage Failure	$15,970,857	$13,451,578	($2,519,279)
Non-Discretionary Sub-total	*$43,114,066*	*$41,435,783*	*($1,678,284)*
Asset Condition	$48,224,333	$40,972,374	($7,251,959)
Non-Infrastructure	$1,427,494	$370,627	($1,056,867)
System Capacity & Performance	$12,497,900	$11,977,144	($520,756)
Discretionary Sub-total	*$62,149,727*	*$53,320,145*	*($8,829,582)*
Total Plant Additions	**$105,263,794**	**$94,755,928**	**($10,507,866)**

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 2023, which was $7.8 million, $8.5 million under the forecast of $16.3 million. Non-discretionary Cost of Removal was $4.6 million, which was $0.1 million over the budgeted amount of $4.4 million. Discretionary Cost of Removal totaled $3.2 million, which was $8.7 million under the budgeted amount of $11.9 million, primarily caused by the deferral of removal work at the Pawtucket 1 substation (Southeast Substation) and Dyer Street Substation to future years.

Table 3
Cost of Removal by Category

	Budget	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$2,487,000	$1,990,056	($496,944)
Damage Failure	$1,946,000	$2,574,112	$628,112
Non-Discretionary Sub-total	*$4,433,000*	*$4,564,168*	*$131,168*
Asset Condition	$10,250,000	$1,629,136	($8,620,864)
Non-Infrastructure	$0	$2,016	$2,016
System Capacity & Performance	$1,617,000	$1,577,240	($39,760)
Discretionary Sub-total	*$11,867,000*	*$3,208,392*	*($8,658,608)*
Total Cost of Removal	**$16,300,000**	**$7,772,560**	**($8,527,440)**

II. ISR Plan Fiscal Year 2023 Capital Spending Summary

As shown in Table 4 below, capital spending totaled $108.4 million, which was $3.7 million over the budget of $104.7 million.

Table 4
Capital Spending by Category

	Budget	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$27,182,550	$31,726,588	$4,544,038
Damage Failure	$14,250,910	$17,461,118	$3,210,208
Non-Discretionary Sub-total	*$41,433,460*	*$49,187,706*	*$7,754,246*
Asset Condition	$24,978,600	$23,370,422	($1,608,178)
Non-Infrastructure	$1,520,000	$1,553,797	$33,797
System Capacity & Performance	$9,188,070	$12,630,631	$3,442,561
Sub-total (excl. Large Projects)	*$35,686,670*	*$37,554,851*	*$1,868,181*
Large Projects Tracked Separately	$27,629,490	$21,701,442	($5,928,048)
Discretionary Sub-total	*$63,316,160*	*$59,256,293*	*($4,059,867)*
Total Capital Investment in System	**$104,749,620**	**$108,443,999**	**$3,694,379**

III. ISR Plan Fiscal Year 2023 Capital Spending by Key Driver Category

1. Non-Discretionary Spending

a. *Customer Request/Public Requirement*

Capital spending for 2023 in the Customer Request/Public Requirement category was $31.7 million, which was $4.5 million over the budget of $27.2 million. The major drivers of this variance are:

- Spending on Third-Party Attachment projects was over budget by $0.4 million at year end. Customer advances were collected at the end of the previous year for work that was completed in 2023.

- Spending activity, net of Distributed Generation ("DG") customer contributions, in the DG category was $3.7 million. As stated during the March 9, 2022 hearing, the Company undertook a review of DG projects. The Company reviewed $4.8 million in plant additions and determined that $1.2 million will remain in rate base. These plant additions represent system improvements or projects where the actual costs exceeded the estimate, and the difference could not be collected from the developer. The Company is in the process of reviewing the remainder of the projects and validating assumptions with National Grid. From this review, the Company has decided to remove the remaining plant additions associated with DG projects from the revenue requirement until a review of each project is completed. The Company anticipates that any plant additions associated with the review will be incorporated into the Fiscal Year ("FY") 2024 ISR Plan Annual Reconciliation. The 2023 spending will also be reviewed in a similar manner.

- Spending for meter purchases was essentially on budget at $1.6 million. Spending in the meter blanket project and Landline Meter Replacement projects was under budget because of the deferral of work.

- Capital spending on New Business work was $2.1 million over budget because of emerging customer work that exceeded the reserves established in the budget. The Company had one large customer job totaling $2.6 million during the Plan Year. Blanket project spending was $0.8 million under budget, and spending on specific projects was $2.9 million over budget.

- Capital spending on Public Requirements projects was $0.6 million, $0.7 million under budget. Spending under the blanket project was essentially on budget. Spending, net of contributions, for specific projects and billing under the joint-owned pole agreement was less than budget.

- Capital spending for the purchase of transformers was $5.8 million, $1.0 million over budget. Supply chain challenges continue to impact the price and quantity of purchases. These include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. During 2023, the Company sought alternate sources of supply, placed proactive orders to mitigate future supply gaps, and increased inventory levels to support work plans and respond to emergencies.

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

Table 5
Customer Request/Public Requirement Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Customer Request / Public Requirement	Third-party Attachments	$260,000	$654,988	$394,988
	Distributed Generation	1,000,000	3,750,295	2,750,295
	Land and Land Rights	475,000	463,795	(11,205)
	Meters & Related Work	2,740,000	1,918,099	(821,901)
	New Business – Commercial	8,950,000	10,379,162	1,429,162
	New Business – Residential	7,060,000	7,695,233	635,233
	Outdoor Lighting	560,000	378,971	(181,029)
	Public & Regulatory Requirement	1,337,550	602,771	(734,779)
	Transformers & Related Equipment	4,800,000	5,761,392	961,392
	Strategic DER Investments	0	121,884	121,884
	Customer Request / Public Requirement Spending	**$27,182,550**	**$31,726,588**	**$4,544,038**

b. Damage/Failure

Capital spending in the Damage/Failure category was $17.5 million, which was $3.2 million over the budget of $14.3 million. This variance was driven by the following:

- Spending in the Overhead Line and Substation Damage/Failure Blanket Projects was $13.2 million, $2.6 million over budget. The Company continued to review the work under these blanket projects each month to make sure only work related to failed assets is categorized in the Non-Discretionary portfolio.

- During ISR Fiscal Year 2022 the Westerly #2 transformer failed and a spare transformer was installed. Capital spending of $0.4 million took place during 2023, $0.3 million under budget. Delivery of the spare transformer has been delayed until June 2024.

- Reserves of $1.0 million were included in the budget to cover the failure of large assets. In August 2022, the metal clad switchgear at Nasonville Substation was damaged beyond repair because of a feeder fault. The failed switchgear will be replaced with an open-air straight bus that will include a main breaker, capacitor breaker, and three feeder breakers. Removal of the failed equipment, design, engineering, and procurement of long lead time materials for the replacement began immediately and will be completed by the Spring of 2024. Capital spending on this project has been $0.7 million to date.

- Actual storm costs of $3.1 million exceeded budgeted storm costs by $1.2 million.

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

Table 6
Damage/Failure Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Damage / Failure	Damage/Failure	$12,325,910	$14,339,333	$2,013,423
	Major Storms	1,925,000	3,121,785	1,196,785
	Damage / Failure Spending	**$14,250,910**	**$17,461,118**	**$3,210,208**

2. Discretionary Spending

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

Capital spending in the Asset Condition category excluding Large Projects was $23.4 million, which was $1.6 million under the budget of $25.0 million. The following projects and programs were included in this category of spending:

- Capital spending on inspection and maintenance work ("I&M") was $0.9 million for the year, under budget because of the focus on addressing priority work and the write off of old work. The write off was recorded in May 2022 and totaled $1.2 million.

- Capital spending for the Franklin Square Breaker project totaled $2.1 million, $0.3 million over budget. Last year, the Franklin Square Breaker Replacement project was under budget because of vendor unavailability. The breakers purchased last year were installed in the first quarter of this year and additional breakers for Franklin Square were ordered. Receipt of these breakers and installation will take place next year. The replacement of the breakers at Drumrock Substation was deferred.

  Capital spending on the Underground Cable Replacement program was $4.0 million, under budget by $1.7 million primarily because of limited cable supply. Efforts were shifted to the Underground Residential Development ("URD") program as materials and crews were available. Capital spending on the URD program totaled $8.0 million, $3.0 million over budget.

- Minimal spending occurred on the 3763 Pole Replacement project because of material availability and delivery dates. Payments for materials were made in March 2023 and construction will be completed next year.

- The Asset Replacement Blanket projects were approximately $5.4 million, $0.2 million over budget.

- Capital spending for fencing for the South Street Substation project totaled $1.1 million. This project had been deferred in previous years because of site requirements including completing a seawall, weatherproofing of the building, and testing of the ground grid, as well as contractor availability.

b. Asset Condition – Separately Tracked Large Projects

During 2023, capital spending on the Southeast Substation, Dyer Street Substation and Providence Area projects in the Asset Condition category was $20.9 million, $2.4 million under the budget of $23.3 million.

- Capital spending for the Southeast Substation project was $0.8 million for the Plan Year. The Dunnell Park substation portion of this project is complete. The majority of the assets associated with the distribution line project are in service. The engineering for the Pawtucket #1 Substation project is complete and building demolition will begin in January 2024. The outage was pushed from August 2023 because of supply chain delays.

- Capital spending on the Dyer Street Substation project was $10.9 million. Capital spending during the year related to the installation of the metal clad switchgear deferred from the previous year, installation of transformers, and civil work. During December 2022, the substation portion of the project was placed in service. The distribution line portion of the project, along with civil work and building demolition, was delayed because of late delivery of cable. This work has been shifted into FY 2024 ISR Plan and is not reflected in the Plan's budget.

- Capital spending on the Phase 1A projects of the Providence Study (Admiral Street Substation) was $1.7 million. The assets associated with this project are in service. Minor removal work will take place in the next year.

- Capital spending on the Phase 1B projects of the Providence Study was $6.0 million against the budget of $16.6 million. Construction began in April 2022. The underspend for the year was caused by the following:

    - Manhole and duct bank work were pushed out because of the winter moratorium.

    - A construction contract bid came in lower than expected.

    - Resources were pulled from the Olneyville construction for customer emergent work.

- Capital spending on the Phase 2 projects of the Providence Study was minimal as was the budget.

- Capital spending on the Phase 4 projects of the Providence Study (Knightsville Substation) was $1.5 million. Engineering, sequencing, and material procurement have been completed so that construction and civil work can begin in the next year.

For additional information on the large project variances, please see Attachment G to the Company's FY 2023 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2023 (Docket No. 5209) filed with the PUC on May 15, 2023. A copy of this report is provided as Attachment 1.

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

Table 7
Asset Condition Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Asset Condition	Asset Replacement	$21,978,600	$22,428,669	$450,069
	Asset Replacement - I&M	3,000,000	941,753	(2,058,247)
	Asset Replacement - Large Projects	23,310,110	20,868,149	(2,441,961)
	Asset Condition Spending	**$48,288,710**	**$44,238,572**	**($4,050,138)**

c. *Non-Infrastructure*

Capital spending in the Non-Infrastructure spending rationale was $1.6 million as of March 31, 2023, including $1.2 million in capital overheads. These charges will be transferred from the Non-Infrastructure category to the appropriate work orders through the normal capital allocation process during the FY 2024 ISR Plan Year. Minimal spending took place on the Copper to Fiber Conversion project because of the amount of work requested by the third party. The remaining spend in the category relates to purchases of general equipment under the blanket project.

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

Table 8
Non-Infrastructure Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Non-Infrastructure	Corporate Overheads	$0	$1,159,681	$1,159,681
	General Equipment	250,000	306,757	56,757
	Telecommunications	270,000	3,045	(266,955)
	Copper to Fiber Conversions	1,000,000	84,314	(915,686)
	Non-Infrastructure Spending	**$1,520,000**	**$1,553,797**	**$33,797**

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

Capital spending for 2023 for the System Capacity and Performance category was $12.6 million, which was $3.4 million over the 2023 budget of $9.2 million. This variance was driven primarily by the following projects:

- Capital spending on the Aquidneck Island projects was $1.1 million, which was $0.4 million over the budget of $0.7 million. Improvements at Harrison, Kingston., and Merton substations continued from the previous year.

- Capital spending on New Lafayette substation project was $1.0 million, which was $1.9 million under budget because of transmission outage coordination issues requiring deferring work on this project.

- Capital spending on Volt/VAR Optimization ("VVO") projects was $0.6 million. This spending was deferred from previous years.

- Capital spending on Energy Management System ("EMS") projects was $1.5 million, $0.4 million over budget. The Bristol EMS expansion and breaker replacement project was completed and put in service. Work on the Bonnet EMS expansion will continue into the next year.

- In the previous year, certain projects related to load shifts because of the COVID-19 pandemic, including work on the 59F3 and 72F5 Lines and some smaller blanket level work, were deferred. Work has progressed on these projects and capital spending totaled $0.9 million. The Company continues to monitor load and takes immediate action to manage the system safely and reliably.

- Capital spending for the Mainline Recloser Enhancement program totaled $1.7 million during 2023. Spending was for planning, engineering, design, and procurement in preparation for installation in the FY 2024 ISR Plan Year.

- Capital spending that took place under the System Capacity & Performance blanket projects was $3.4 million, $1.4 million over budget. The primary reason for the overspend was the installation of line reclosers to improve reliability. Frequent circuit interruptions (approximately one interruption every third day during blue sky conditions) and low numbers of reclosers per circuit were identified during the Summer of 2022. The installation of these pole-top reclosers allows for feeder sectionalization during fault conditions and minimizes the number of customers interrupted.[2]

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

Capital spending on the East Providence and Warren substation projects was $0.8 million. These projects were under budget due to project delays. For additional information, please see Attachment G to the Company's 2023 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2023 (Docket 5209) filed with the PUC on May 15, 2023. A copy of this report is attached as Attachment 1.

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

Table 9
System Capacity & Performance Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
System Capacity & Performance	Load Relief	$2,560,350	$3,335,292	$774,942
	Reliability	$6,627,720	$9,295,340	$2,667,620
	SC&P - Large Projects	$4,319,380	$833,293	($3,486,087)
	System Capacity & Performance Spending	**$13,507,450**	**$13,463,924**	**($43,526)**

IV. 2023 Vegetation Management

In 2023, the Company completed 100% of its work plan, 1,376 miles of distribution cycle pruning, at a cost of $12.7 million. Table 10 below provides the spending components. The Company made the decision to focus some additional spend on cycle trimming and the removal of hazardous trees and limbs. Using the Company's risk reduction tool and data analytics, cycle trimming clearance distances were expanded for some of the current year's feeders to improve reliability. In addition, cycle trimming along the 85T1 feeder in Westerly and Hopkinton was moved forward to reduce tree-related outages. The overspend on the police and flagger category can be attributed to the additional work performed and increased costs of police and flagging details.

[2] Or increases the customers restored in less than 5 minutes.

Table 10
Vegetation Management O&M Spending

	Budget	Actuals	Variance Over / (Under)
Cycle Pruning (Base)	$7,300,000	$7,973,587	$673,587
Hazard Tree	1,750,000	1,425,184	(324,816)
Sub-T (on & off road)	350,000	183,984	(166,016)
Police/Flagman Details	775,000	1,010,197	235,197
Pockets of Poor Performance	200,000	181,757	(18,243)
Risk Reduction - Extra	0	426,847	426,847
Core Crew (all other activities)	1,500,000	1,546,538	46,538
Total VM O&M Spending	**$11,875,000**	**$12,748,094**	**$873,094**

V. 2023 Other O&M

For 2023, the Company completed 100% of its annual overhead structure inspection goal with an associated spend of $0.5 million. Table 11 below provides the spending components in the Other O&M category.

Table 11
Other O&M Spending

	Budget	Actuals	Variance Over / (Under)
Opex Related to Capex	$540,000	$200,395	($339,605)
Repair & Inspections Related Costs	475,000	511,977	36,977
System Planning & Protection Coordination Study	25,000	0	(25,000)
VVO/CRV Program	224,000	270,660	46,660
Total I&M O&M Spending	**$1,264,000**	**$983,032**	**($280,968)**

For additional information about the I&M program, please see the Company's FY 2023 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2023 (Docket No. 5209) filed with the PUC on May 15, 2023. A copy of this report is attached as Attachment 1.

VI. Reliability Performance

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance metrics in CY 2022, with SAIFI of 0.866 against a target of 1.05, and SAIDI of 62.48 minutes, against a target of 71.9 minutes. For additional information on reliability and major event days, please refer to the 2022 Service Quality Report filed under Docket No. 3628 on April 28, 2023. A copy is included in this report as Attachment 2.

Attachment 1

Quarterly Report for the Fourth Quarter Period Ending March 31, 2023

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

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

Rhode Island Energy™
a PPL company

May 15, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 5209 - FY2023 Electric Infrastructure, Safety, and Reliability Plan Quarterly Update – Fourth Quarter Ending March 31, 2023

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's fiscal year ("FY") 2023 Electric Infrastructure, Safety, and Reliability ("ISR") Plan quarterly update for the fourth quarter ending March 31, 2023. 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 filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

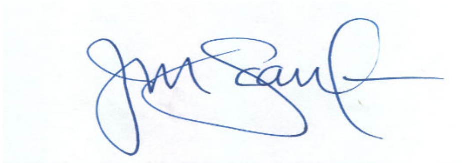
Enclosures

cc: Docket No. 5209 Service List

Certificate of Service

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

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



___________________________________ May 15, 2023

Joanne M. Scanlon Date

Docket No. 5209 – The Narragansett Electric Company d/b/a Rhode Island Energy Electric ISR Plan FY 2023
Service List as of 10/13/2022

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. 280 Melrose St. Providence, RI 02907 Adam S. Ramos, Esq. **Hinckley Allen** 100 Westminster Street, Suite 1500 Providence, RI 02903-2319 Stephanie Briggs Patricia C. Easterly Susan M. Toronto Alan LaBarre Ryan Constable Kathy Castro Jeffrey Oliveira	amarcaccio@pplweb.com; cobrien@pplweb.com; jscanlon@pplweb.com; aramos@hinckleyallen.com; sbriggs@pplweb.com; pceasterly@RIEnergy.com; smtoronto@RIEnergy.com; ATLaBarre@RIEnergy.com; rconstable@RIEnergy.com; krcastro@RIEnergy.com; joliveira@pplweb.com;	401-784-4263
National Grid Melissa Little Caitlin Broderick Ryan Moe Daniel Gallagher Theresa Burns Scott McCabe	Melissa.Little@nationalgrid.com; Caitlin.broderick@nationalgrid.com; Ryan.moe@nationalgrid.com; Daniel.gallagher@nationalgrid.com; Theresa.Burns@nationalgrid.com; Scott.McCabe@nationalgrid.com;	
Division of Public Utilities (Division) Mark Simpkins, Esq.	Mark.A.Simpkins@dpuc.ri.gov; jon.hagopian@dpuc.ri.gov;	

Jon Hagopian, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	EGolde@riag.ri.gov; John.bell@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov; Margaret.l.hogan@dpuc.ri.gov; Paul.roberti@dpuc.ri.gov; Linda.george@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; Christy.hetherington@dpuc.ri.gov;	
Rhode Island Attorney General's Office Nicholas Vaz, Esq.	nvaz@riag.ri.gov;	
Alison Hoffman, Esq.	ahoffman@riag.ri.gov;	
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources Al Vitali, Esq.	Albert.vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Matthew.Moretta.INT@energy.ri.gov;	
File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Esq. Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107
Matt Sullivan, Green Development LLC	ms@green-ri.com;	

Electric Infrastructure, Safety, and Reliability Plan
Plan Year 2023 Fourth Quarter Update
For the Year Ending March 31, 2023

EXECUTIVE SUMMARY

As shown in Attachment A, The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") spent \$108.5 million for capital projects against a budget of \$104.8 million during the Plan Year 2023 (i.e., April 1, 2022 through March 31, 2023) for its electric infrastructure, safety, and reliability ("ISR") plan. Non-Discretionary spending was \$49.3 million, \$7.8 million over budget. Discretionary spending, including the separately tracked large projects, was \$59.2 million, \$4.1 million under budget. Spending in each of these categories is addressed in more detail below.

I. Plan Year 2023 Capital Spending by Key Driver Category

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

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

During the year ending March 31, 2023, capital spending in the Customer Request/Public Requirement category was $31.8 million, which was $4.6 million over the budget of $27.2 million. The major drivers were:

- As forecasted, net spending on Third-Party Attachment projects exceeded the budget by $0.4 million. For several projects, customer advances were collected at the end of the previous year and the work was completed this year.

- Net spending activity in the Distributed Generation ("DG") category was $3.7 million for the year ending March 31, 2023. The Company will report on its review of DG Projects to the Commission in the Annual Reconciliation that will be filed by August 1, 2023.

- Capital spending on New Business work was $2.1 million over budget at year end primarily due to spending on emerging customer work that exceeded the reserves established in the budget.

- Public Requirements capital spending was $0.6 million, $0.7 million under budget. The Blanket project's capital spending was essentially on budget. Net spending for specific projects and billing under the joint-owned pole agreement were less than the budgeted reserves.

- Meter purchases came in essentially on budget. Detail meter and instruments are shown in Attachment H to this report. The Landline Meter Replacement project was deferred and the Company will start the program in the 2024 ISR Year.

- In the previous year, Strategic Distributed Energy Resources ("DER") projects were under budget because construction on some Hopkins Hill feeder monitors was deferred. Construction of these feeders has been completed and the assets have been placed into service. Actual capital spending was $122,000.

- Capital spending for transformers was $5.7 million, $0.9 million over budget. Supply chain challenges continue to impact price and quantity of purchases. These include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. During 2023, the Company sought alternate sources of supply, continued to place proactive orders to mitigate future supply gaps, and increased inventory levels to support work plans and respond to emergencies.

b. Damage/Failure

During the 2023 ISR Plan Year, capital spending in the Damage/Failure category was $17.5 million, which was $3.2 million over budget.

- Spending in the Overhead Line and Substation Damage/Failure Blanket Projects was $13.2 million, $2.6 million over budget. The Company continues to review the work under these blanket projects each month to make sure only work related to failed assets is categorized in the Non-Discretionary portfolio.

- Actual capital spending related to storms and weather-related events was $3.1 million, $1.2 million over budget. Larger storms took place in December 2022 and February 2023. Capital spending for these storms totaled $0.8 million.

- In August 2022, the metal clad switchgear at the Nasonville Substation was damaged beyond repair due to a bus fault. The failed switchgear will be replaced with an open-air straight bus that will include a main breaker, capacitor breaker, and four feeder breakers. Removal of the failed equipment has been completed, design and engineering, and procurement of materials is on-going. Once materials and environmental permits are received, it is estimated that the work will take six to nine months to complete. Capital spending on this project has been $0.7 million to date.

- During ISR Plan Year 2022, the Westerly #2 Transformer failed and a spare transformer was installed. Capital spending of $0.4 million took place during 2023, $0.3 million under budget. Delivery of the spare transformer is scheduled for June 2024.

2. Discretionary Spending

a. Asset Condition (Without Separately Tracked Large Projects)

During the 2023 ISR Plan Year, capital spending in the Asset Condition category (excluding separately tracked large projects) was $23.4 million, which was $1.6 million under budget. The major drivers of this variance were as follows:

- Net capital spending on inspection and maintenance work ("I&M") was $0.9 million for the year, under budget because of the focus on addressing priority work and the write off of old work. The write off was recorded in May 2022 and totaled $1.2 million.

- Capital spending for the Franklin Square Breaker project totaled $2.1 million, $0.3 million over budget. Last year, the Franklin Square Breaker Replacement project was under budget due to vendor unavailability. The breakers purchased last year were installed in the first quarter of this year and additional breakers for Franklin Square were purchased. Installation will take place next year. The replacement of the breakers at Drumrock station was deferred.

- Capital spending on the Underground Cable Replacement program was $4.0 million, under budget by $1.7 million primarily due to limited cable supply. Efforts were shifted to the URD program as materials and crews were available. Capital spending on the URD program totaled $8.0 million.

- Minimal spending occurred on the 3763 Pole Replacement project due to material availability and delivery dates. Payments for materials were made in March 2023 and construction will be completed next year.

- Capital spending for fencing for the South Street Substation project totaled $1.1 million. This project had been deferred from previous years due to site requirements including completing a seawall, weatherproofing of the building, and testing of the ground grid, as well as contractor availability. The Company anticipates additional spending of $0.5 million which was not included in the 2024 ISR Plan Year budget.

b. ***Non-Infrastructure***

Capital spending in the Non-infrastructure spending rationale was $1.6 million as of March 31, 2023, including $1.2 million in the Capital Overheads project. These overheads will be applied to projects in the next year. Minimal spending took place on the Copper to Fiber Conversion project due to the amount of work requested by the third party. The remaining spend relates to purchases of general equipment under the Blanket project.

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

During the year ending March 31, 2023, capital spending for the System Capacity and Performance category was $12.6 million, which was $3.4 million over budget. The major drivers of this variance were as follows:

- Capital spending on the New Lafayette Substation project was $1.0 million, $1.9 million under budget. Transmission outage coordination issues required deferring work on this project.

- Capital spending on Volt/VAR Optimization ("VVO") projects totaled $0.6 million. This spending was deferred from previous years.

- In the previous year, certain projects related to load shifts because of the COVID-19 pandemic, including work on the 59F3 and 72F5 Lines and some smaller blanket level work, were deferred. Work has progressed on these projects and capital spending totaled $0.9 million during the 2023 ISR Plan Year. The Company continues to monitor load and takes immediate action to manage the system safely and reliably.

- Capital spending for reclosers totaled $1.7 million during 2023. Spending was for planning, engineering, design, and material purchases.

- During 2023, capital spending on the System Capacity & Performance Blanket projects was $3.4 million, $1.4 million over budget. The primary reason for the overspend was the installation of line reclosers to improve reliability. Frequent circuit interruptions (approximately one interruption every third day during blue sky conditions) and low numbers of reclosers per circuit were identified during the Summer of 2022. The installation of these pole-top reclosers allows for sectionalizing of feeders in fault and overload conditions and minimizes the number of customers without service.

d. Separately Tracked Large Projects

During Plan Year 2023, capital spending on the following Large Projects is separately tracked: Southeast Substation, Dyer Street Substation, Providence Study projects, East Providence Substation, and Warren Substation. Each project is discussed in Attachment G.

e. Large Project Variances

The Company provides explanations for large projects[1] with variances that exceed +/- 10% of the Plan Year budget in quarterly reports. These projects represent $33.4 million of the Plan Year 2023 budget of $104.8 million. This project information is provided in Attachment E.

f. New Distribution System Technology Update

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

3. Investment Placed-in-Service

During the year ending March 31, 2023, $96.7 million of plant additions were placed in service, which was 92% of target. Details by spending rationale are included in Attachment B.

4. Vegetation Management

During the year ending March 31, 2023, the Company completed 1,367 miles or 100% of its annual distribution mileage cycle pruning goal. The Company spent $12.7 million. The Company made the decision to focus some additional spend on cycle trimming and the removal of hazardous trees and limbs. Using the Company's risk reduction tool and data analytics, cycle trimming clearance distances were expanded for some of the current year's feeders to improve reliability. In addition, cycle trimming along the 85T1 feeder in Westerly and Hopkinton was moved forward to reduce tree-related outages. The overspend on the police and flagger category can be attributed to the additional work performed and increased costs of police and flagging details. Attachment C provides the O&M spending and the Enhanced Hazard Tree Mitigation ("EHTM") removal counts by circuit. Of the 750 hazardous trees removed, 537 trees were removed due to Eastern Ash Borer infestation.

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

5. Inspection and Maintenance

I&M program costs for the ISR Plan Year 2023 are shown in Attachment D. This spending includes mobile elevated voltage testing and repairs, which the Rhode Island Public Utilities Commission approved in Docket No. 4237.
The Company identified one Level I deficiency during the Plan Year 2023. When Level I deficiencies are identified, they are repaired immediately or within 30 days of the inspection.

The Company began its annual inspection of targeted overhead structures and elevated voltage testing on January 1, 2023 as inspections and elevated voltage testing now take place on a calendar year basis. During the Plan Year 2023, the Company's manual elevated voltage testing identified one instances of elevated voltage. The table below shows the number of units tested during this period.

Manual Elevated Voltage Testing				
Manual Elevated Voltage Testing	Total System Units Requiring Testing	Units Completed 1/1/23 thru 3/31/23	Units with Voltage Found (>1.0v)	Percent of Units Tested with Voltage (>1.0v)
Distribution Facilities	274,396	16,298	0	0.000%
Underground Facilities	12,438	0	0	0.000%
Street Lights and Signal Controls	4,929	0	0	0.000%

Attachment A

Capital Spending by Spending Rationale
For the Year Ending March 31, 2023
($000)

	Plan Year 2023		
	Budget	**Actuals**	**Over Spend / (Under Spend)**
Customer Request/Public Requirement	$27,183	$31,799	$4,616
Damage Failure	14,251	17,461	3,210
Non-Discretionary Spending	***41,433***	***49,260***	***7,827***
Asset Condition	24,979	23,370	(1,608)
Non-Infrastructure	1,520	1,554	34
System Capacity & Performance	9,188	12,631	3,443
	35,687	***37,555***	***1,868***
Large Projects Separately Tracked	27,629	21,701	(5,928)
Discretionary Spending	***63,316***	***59,256***	***(4,060)***
Total Capital Spending	**$104,750**	**$108,516**	**$3,767**

Attachment B

Plant Additions by Spending Rationale
For the Year Ending March 31, 2023
($000)

	Plan Year 2023 Target	Actuals	% of Target Placed In Service
Customer Request/Public Requirement	$27,143	$29,930	110%
Damage Failure	15,971	13,452	84%
Subtotal Non-Discretionary	*43,114*	*43,382*	*101%*
Asset Condition (w/Sep Tracked Large Projects)	48,224	40,972	85%
Non- Infrastructure	1,427	371	26%
System Cap & Perf (w/Sep Tracked Large Projects)	12,498	11,977	96%
Subtotal Discretionary	*62,150*	*53,320*	*86%*
Total Plant Additions	**$105,264**	**$96,702**	92%

Attachment C

Vegetation Management
For the Year Ending March 31, 2023
($000)

Vegetation Management O&M Spending

	2023 Budget	Actual Spending	% Spend
Cycle Pruning (Base)	$7,300	$7,974	109%
Hazard Tree	1,750	1,425	81%
Sub-T (on & off road)	350	184	53%
Police/Flagger Details	775	1,010	130%
Pockets of Poor Performance	200	182	91%
Risk Reduction - Extra	0	427	0%
Core Crew (all other activities)	1,500	1,547	103%
Total O&M Spending	**$11,875**	**$12,748**	**107%**

Enhanced Hazard Tree Mitigation Update

District	Circuit	Substation	Hazard Tree Removals
Capital	4F1	Barrington	44
Capital	5F1	Warren	5
Capital	127W40	Nasonville	35
Capital	126W50	Washington	46
Coastal	52F3	Warwick	38
Capital	34F2	Chopmist	41
Capital	38F1	Putnam Pike	37
Capital	34F1	Chopmist	169
Coastal	54F1	Coventry	45
Capital	34F3	Chopmist 34	20
Coastal	68F1	Kenyon 68	46
Coastal	54F1	Coventry 54	45
Coastal	88F1	Tower Hill 88	109
Coastal	155F8	Chase Hill 155	13
Coastal	155F6	Chase Hill 155	12
Coastal	155F4	Chase Hill 155	19
Coastal	16F2	Westerly 16	18
Coastal	63F6	Hopkins Hill 63	8
Totals			**750**

Attachment D

Inspection and Maintenance Program and Other O&M Spending
For the Year Ending March 31, 2023
($000)

	2023 Budget	Actuals	% Spend
Opex Related to Capex	$540	$200	37%
Inspections & Repair Related Costs	475	512	108%
System Planning & Protection Coordination Study	25	0	0%
VVO/CRV Program	224	271	121%
Total O&M Spending	**$1,264**	**$983**	

Attachment E

Project Variance Report
For the Year Ending March 31, 2023
($000)

	Plan Year 2023			
Project Description	**Budget**	**Actuals**	**Over / (Under)**	**Variance Cause**
New Lafayette Substation	$2,914	$1,010	($1,904)	Schedule adjusted due to transmission outage coordination issues.
Dyer Street Substation (at South Street)	$3,500	$10,877	$7,377	See Attachment G for additional details.
Providence Study - Phase 1A	$1,484	$1,718	$233	See Attachment G for additional details.
Providence Study - Phase 1B	$16,585	$5,992	($10,593)	See Attachment G for additional details.
Providence Study - Phase 2	$300	$14	($286)	See Attachment G for additional details.
Providence Study - Phase 4	$1,217	$1,480	$263	See Attachment G for additional details.
East Providence Substation	$2,495	$461	($2,034)	See Attachment G for additional details.
Warren Substation	$1,824	$372	($1,452)	See Attachment G for additional details.
Franklin Sq Breaker Replacement	$1,837	$2,128	$291	FY22 breaker carryover work installed and additional breakers on order. Installation will take place next year.
South Street Substation	$0	$1,123	$1,123	Substation property fencing.
Mainline Recloser Project	$0	$1,743	$1,743	Project to install mainline reclosers to reduce mainline fault impacts.
3763 Pole Replacements	$1,250	$271	($979)	Deferral of a portion of spending to next year due to material delivery dates. Work can't be done in Winter.
	$33,407	**$27,189**	**($6,218)**	

Attachment F

Damage/Failure Detail by Work Type
For the Year Ending March 31, 2023
($000)

Operation Description	D Line Blanket	Property Damage	D Sub Blanket	Storms	Specifics	Grand Total
Engineering/Design/Supervision	$ 827	$ 99	$ 45	$ 178	$ 2	$ 1,150
OH Elec Distribution	3,345	298	0	1,839	0	5,482
OH Transformers/Capacitors/Regulators/Meters	585	(2)	0	150	0	733
Other	1,009	158	(290)	1,289	544	2,709
Outdoor Lighting	12	2	0	0	0	13
Substation	0	0	867	0	424	1,291
Switching and Restoration	76	(16)	159	1	0	220
Traffic Control	270	104	0	36	0	410
UG Elec Distribution	2,036	422	0	92	0	2,550
UG Transformers/Capacitors/Regulators/Meters	181	(0)	0	8	0	189
Not Available	2,843	470	334	(471)	191	3,368
Total before reclassification	**11,184**	**1,533**	**1,115**	**3,122**	**1,161**	**18,115**
Reclassification adjustment - D/F to A/R	(654)					(654)
Total after reclassification	**$ 10,530**	**$ 1,533**	**$ 1,115**	**$ 3,122**	**$ 1,161**	**$ 17,461**

Attachment G

Separately Tracked Large Projects
For the Year Ending March 31, 2023

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

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Southeast Substation Project	**$787**	**$23,716**	**$223**	**$23,131**

Capital spending for the Southeast Substation project was $0.8 million for the Plan Year. The Dunnell Park substation portion of this project is complete. The majority of the assets associated with the distribution line project are in service. The engineering for the Pawtucket #1 Substation project is complete and building demolition will begin in January 2024.

In total, the Company currently expects capital spending of $23.7 million for this project as compared with the estimate when sanctioned of $21.1 million. Additional spending was necessary because of field conditions requiring environmental management of an additional volume of soil; construction site congestion requiring additional resources such as crane and other equipment rentals; increased costs on final civil work at Dunnell Park substation; and the reconfiguration and equipment on the distribution network to avoid reliability issues.

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

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Dyer Street Substation Project	**$10,877**	**$25,713**	**$3,500**	**$16,504**

During the year ending March 31, 2023, capital spending on the Dyer Street Substation project was $10.9 million. Capital spending during the year related to the installation of the metal clad switchgear which was deferred from the previous year, transformers, and civil work. Capital spending came in under the amount forecasted in the third quarter report because of delays in delivery and the condition of the delivered conduit. During December 2022, the substation portion of the project was placed in service.

The total project cost forecast increased due to:

- Supply chain delays adding a year to the project schedule
- Scope increases due to underground obstructions and a collapsed duct bank
- Underground construction bids higher than expected

The remaining project spend includes the work deferred due to material delays and scope increase, as well as the completion of the civil work and building demolition.
As discussed in the Company's response to Record Request No. 8 issued under Docket No. 22-53-EL at the Commission's Evidentiary Hearings on March 8 and 9, 2023, the Company has written off $0.9 million of costs associated with the refurbishment of the DC Building. Once the 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 the ISR rate base or revenue requirement.

Providence Study – Admiral Street Substation - Phase 1A
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Design and Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 1A	**$1,718**	**$8,677**	**$1,484**	**$8,973**

During the year ending March 31, 2023, capital spending on the Phase 1A project of the Providence Study was $1.7 million. The assets associated with this project are all in service. Minor removal work will take place in the next year. In total, capital spending was $8.7 million compared to the $9.0 million budget presented in the 2023 ISR Plan and the estimate of $10.0 million when sanctioned.

Providence Study – Admiral Street Substation - Phase 1B
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Final Engineering/Design and Execute

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 1B	**$5,992**	**$46,512**	**$16,585**	**$45,366**

During the year ending March 31, 2023, capital spending on Phase 1B projects of the Providence Study was $6.0 million against the budget of $16.6 million. Construction began in April 2022.

The underspend for the year was caused by the following major drivers:

- The manhole and duct bank work were pushed out due to the winter moratorium.
- A construction contract bid came in lower than expected.
- Resources were pulled from the Olneyville construction for customer emergent work.

Project spend for the next year includes:

- Manhole and duct bank construction, cable pulling and restoration.
- Admiral St Substation construction and demolition.
- Olneyville conversion construction.

In total, the Company expects capital spending of $46.5 million for this project compared to the $45.4 million budget presented in the 2023 ISR Plan and $45.6 million sanctioning amount.

Providence Study Projects - Phase 2
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Develop & Sanction

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 2	**$14**	**$25,145**	**$300**	**$25,324**

Actual capital spending on the Phase 2 projects of the Providence Study was minimal during the Plan year. In total, the Company currently expects capital spending of $25.1 million for these projects as compared to the $25.3 million budget presented in the 2023 ISR Plan. Work pushed out a year compared to original sanction dates, following the sequencing of predecessor phases of the Providence Study portfolio. Capital spending during the next year will primarily be design work, as design packages are currently out to bid.

Providence Study – Knightsville Substation - Phase 4
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Construction

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 4	**$1,480**	**$19,981**	**$1,217**	**$8,392**

Actual capital spending was $1.5 million on the Phase 4 projects of the Providence Study during the Plan year. During the year, the project team has achieved engineering, sequencing, and material procurement to prepare the conversion work to be in construction during 2024. Additionally, substation civil work will begin in the next year. This phase is expected to have over 40,000 labor hours for the conversion work.

In total, the Company currently expects capital spending of $20.0 million for this phase of the project as compared to the $8.4 million budget presented in the 2023 ISR Plan. As discussed in the 2022 ISR Plan reporting, estimates for the Knightsville substation and distribution line projects have been revised as the projects progress through the project development phase. The earlier estimates were based on higher level engineering information. Primary drivers with associated increased costs were as follows:

- Duct bank and earthwork increases - $0.5 million
- Resourcing, labor, and team costs - $3.3 million
- Contingency, risk, AFUDC, and A&G costs - $7.1 million

East Providence Substation
East Bay Area Study (August 2015)
Current Status – Develop & Sanction

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	**Total Project Cost Forecast**	**FY23 Budget**	**Total Project Cost Forecast**
East Providence Substation	**$461**	**$17,559**	**$2,495**	**$17,025**

During the year ending March 31, 2023, capital spending on the East Providence Substation project was $0.5 million against a budget of $2.5 million. The project has been delayed due to real estate issues. In preparation for construction, design and procurement efforts will take place next year.

In total, the Company currently expects capital spending of $17.6 million for this project compared to the $17.0 million budget presented in the ISR Plan. This project consists of building a new 115/12.4kV substation in East Providence to relieve heavily loaded distribution feeders, address MWh violations, and provide capacity to supply load growth. This new substation is part of a comprehensive plan that eliminates the need for major upgrades on the 23kV sub-transmission system and the need to build a new 115/23kv station at Mink Street.

Warren Substation
East Bay Area Study (August 2015)
Current Status – Develop & Sanction

($ 000's)	Actuals & Current Forecast		ISR Plan Budget	
	FY 2023 Actuals	Total Project Cost Forecast	FY23 Budget	Total Project Cost Forecast
Warren Substation	**$372**	**$10,173**	**$1,824**	**$9,685**

During the year ending March 31, 2023, capital spending on the Warren Substation project was $0.4 million. Final design and procurement have been delayed due to the need to coordinate with external parties. In total, the Company currently expects capital spending of $10.2 million for this project compared to the $9.7 million budget presented in the 2023 ISR Plan. Capital spending was increased for potential flood mitigation. This project encountered delays with permitting along the East Bay Bike Path. It is currently being reviewed with RIDOT and RIDEM. During the next year, the overhead and substation work, independent of the bike path, will continue to progress as the permitting requirements around the underground portion are satisfied.

This project will expand the Warren 115/12.47kV substation by adding two new distribution feeders and two 7.2 MVAR station capacitor banks. The new feeders will be routed into Barrington and used to retire the Barrington substation. This expansion project addresses asset and safety concerns at the Barrington substation and is part of a comprehensive plan that eliminates the need for major upgrades on the 23kV sub-transmission system and the need to build a new 115/23kV station at Mink Street.

Tiverton
Tiverton Area Study 33F6

In the Tiverton area, the DG application for the installation of a new feeder, 33F6, has been approved and the project is progressing. This generation site is expected to be in-service late 2022 or early 2023. The Tiverton Area Study (September 2021) identified the need to extend the proposed 33F6 circuit to the south for thermal (capacity) limits, contingency response capability, and voltage issues. The Study included a cash flow showing the circuit extension to be in-service in 2028. As a result of cost sharing complications that are expected to occur for this project, the Company plans to include the Tiverton 33F6 extension project in Attachment G of future ISR Plan quarterly reports.

Attachment H

Meter Purchases
For the Year Ending March 31, 2023

Quantity of Meters Purchased		
Type	**Description**	**Quantity**
METER	CENTRON - 2S 240V CL200	15,300
METER	CENTRON - 12S ERT CL200	7,920
METER	CENTRON - 16S CL320	240
METER	CENTRON - 3-ERT AMR	480
METER	KV2C METER 9S	192
INSTRUMENT TRANSFORMER	CUR OUTDOOR 70/1 8.4KV	47
INSTRUMENT TRANSFORMER	CUR OUTDOOR 200/1	12
INSTRUMENT TRANSFORMER	CUR OUTDOOR 15KV	15
INSTRUMENT TRANSFORMER	CUR OUTDOOR 5/5 15KV	15
INSTRUMENT TRANSFORMER	CUR OUTDOOR 15/5 15KV	15
INSTRUMENT TRANSFORMER	CUR OUTDOOR 25/5 15KV	23
INSTRUMENT TRANSFORMER	CUR OUTDOOR 50/5 15KV	16
INSTRUMENT TRANSFORMER	CUR OUTDOOR 75/5 15KV	42
INSTRUMENT TRANSFORMER	CUR OUTDOOR 100/5 15KV	12
INSTRUMENT TRANSFORMER	800:5 BASE BUSHINGS	60
INSTRUMENT TRANSFORMER	2000:5 BASE BUSHINGS	24
INSTRUMENT TRANSFORMER	3000:5 BASE BUSHINGS	24
INSTRUMENT TRANSFORMER	200:5 CAP	10
	TOTAL	**24,447**

Attachment 2

2022 Electric Service Quality Report

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

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

Rhode Island Energy™
a PPL company

April 28, 2023

VIA ELECTRONIC MAIL

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

RE: Docket 3628 – 2022 Service Quality Report (Electric Operations)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), enclosed, please find an electronic version[1] 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, 2022 through December 31, 2022 (the "2022 Service Quality Report" or "Report"). As indicated in the Report, the Company's performance for both reliability and customer service was within acceptable regulatory levels and, as a result, the Company did not incur a penalty.

The 2022 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.[2] The purpose of the SQ Plan is to ensure that customers receive a reasonable level of service. To this end, the SQ Plan establishes performance standards for service reliability, which includes the categories of interruption frequency and interruption duration, and for customer service, which includes the categories of customer contact and telephone calls answered. For each category, a benchmark or range representing a regulatory acceptable performance is set forth. If the Company's performance falls below the acceptable range in any of the four categories, a penalty is assessed. The Company cannot earn a monetary award for exceeding expectations; however, it can accrue offsets for good performance in one category which may be used to offset a penalty incurred in the other categories. For additional details on the SQ Plan, please see Attachment 1 of the Settlement Agreement.[3]

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[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

[2] 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).

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

For 2022, the Company did not incur a penalty. Specifically, the Company's performance fell within an acceptable regulatory range for each of the four categories, meaning there were no penalties assessed. For a summary of the results, please see Section 2 of the Report.

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

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 3628 Service List

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

2022 Service Quality Report

April 28, 2023

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

Submitted by:

Rhode Island Energy™
a PPL company

TABLE OF CONTENTS

SECTION 1: RELIABILITY AND CUSTOMER SERVICE PERFORMANCE STANDARDS

Interruption Frequency and Duration

Under the Service Quality Plan, an interruption is defined as the loss of electric service to more than one customer for more than one minute. The interruption duration is defined as the period of time, measured in minutes, from the initial notification of the interruption event to the time when service has been restored to the customers. Interruptions are tracked using System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). SAIFI is calculated by dividing the total number of customers interrupted by the total number of customers served. SAIFI measures the number of times per year the average customer experienced an interruption. This is an average, so in any given year some customers will experience no interruptions, and some will experience several interruptions. SAIDI measures the length of interruption time that the average customer experienced for the year. It is calculated by dividing the total customer minutes of interruption by the total number of customers served. Certain events are defined as Major Event Days and are excluded from the calculation of reliability performance standards for penalty and offset assessment. There was one Major Event Day that occurred during 2022. The Major Event Day was December 23.

2022 Total Frequency Standard		2022 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	0.866	$0
0.75-0.83	linear interpolation		
Less than 0.75	$229,000		

2022 Duration (SAIDI) Standard		**2022 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	62.48	$0
36.7-45.8	linear interpolation		
Less than 36.7	$229,000		

CUSTOMER SERVICE PERFORMANCE STANDARDS

Customer Contact Survey

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

2022 Customer Contact Standard		2022 Customer Contact Results	
Percent Satisfied	(Penalty)/Offset	Percent Satisfied	Annual (Penalty)/Offset
Less than 74.4%	($184,000)		
74.4%-78.7%	linear interpolation		
78.8%-87.6%	$0	80.90%	$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.

2022 Calls Answered Standard		**2022 Calls Answered Results**	
% Answered Within 20 Seconds	(Penalty)/Offset	% Answered Within 20 Seconds	Annual (Penalty)/Offset
Less than 53.5%	($184,000)		
53.5% - 65.7%	linear interpolation		
65.8% - 90.4%	$0	85.90%	$0
90.5% - 100.0%	linear interpolation, to maximum of $46,000		

SECTION 2: CALCULATION OF PENALTY/OFFSET

Rhode Island Energy
2022 Results of Service Quality Plan
Calculation of Penalty/Offset

Performance Standard	Potential Penalty (a)	Potential Offset (b)	2022 Results (c)	Maximum Penalty (d)	One Std Dev. Worse Than Mean (e)	Mean (f)	One Std Dev. Better Than Mean (g)	Maximum Offset (h)	Annual (Penalty)/ Offset (i)
Reliability - Frequency	$ 916,000	$ 229,000	0.87	1.18	1.05	0.94	0.84	0.75	$0
Reliability - Duration	$ 916,000	$ 229,000	62.5	89.9	71.9	57.5	45.9	36.7	$0
Customer Service - Customer Contact Survey	$ 184,000	$ 46,000	80.9%	74.4%	78.8%	83.2%	87.6%	92.0%	$0
Customer Service - Telephone Calls Answered	$ 184,000	$ 46,000	85.9%	53.5%	65.8%	78.1%	90.4%	100.0%	$0
Total Penalty/Offset	$ 2,200,000	$ 550,000							$0

Notes:

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

Column (c) represents the actual 2022 annual results for the performance standards listed in the first column.

Column (i) is calculated as follows:

- For Reliability Standards:

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

- For Customer Service Standards:

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

SECTION 3: ADDITIONAL REPORTING CRITERIA

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

1. **Reporting Requirement:** Each quarter, the Company will file a report of 5% of all circuits designated as worst performing on the basis of customer frequency. Included in the report will be:
   1. The circuit ID and location.
   2. The number of customers served.
   3. The towns served.
   4. The number of events.
   5. The average duration.
   6. The total customer minutes.
   7. A discussion of the cause or causes of events.
   8. A discussion of the action plan for improvements including timing.

   Results: The Company filed its first quarter 2022 feeder ranking results on July 26, 2022, the second quarter results on October 27, 2022, the third quarter results on November 15, 2022, and fourth quarter results on February 2, 2023.

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 2022, with the final report for the 13 months ended December 2022 filed on January 23, 2023.

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

Results: During 2022, the Company's annual meter reading performance (as an average of monthly percentage of meters read) was 98.88% compared to 98.60% in 2021, and 98.19% during 2020. The following table details the percentage of meters read per month for 2022, 2021 and 2020.

Monthly Percentage of Meters Read

	2022	2021	2020
January	98.71%	98.59%	99.01%
February	98.71%	98.53%	99.07%
March	98.75%	98.63%	98.72%
April	98.90%	98.70%	97.85%
May	98.96%	98.70%	97.88%
June	98.95%	98.75%	97.67%
July	98.95%	98.66%	97.92%
August	99.12%	98.36%	97.05%
September	98.96%	98.83%	98.27%
October	98.76%	98.57%	98.32%
November	98.95%	98.18%	98.38%
December	98.87%	98.69%	98.17%
YTD Average	98.88%	98.60%	98.19%

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

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

Results: IEEE Std. 1366-2012[1] identifies reliability performance during both day-to-day operations and Major Event Days. Major Event Days represent those few days during the year on which the energy delivery system experienced stresses beyond that normally expected, such as severe weather. A day is considered a Major Event Day if the daily SAIDI exceeds a threshold value, calculated using the IEEE methodology. For 2022 the T_{MED} value was 6.88 minutes of SAIDI (using IEEE Std. 1366-2012 methodology). There was one major storm day that exceeded this threshold in 2022. The storm occurred on December 23. The storm details are described below.

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

December 23, 2022, Storm

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

   The storm began on December 22, with scattered interruptions starting at 4:00 a.m. in the early morning of December 23. The peak was around 8:19 a.m. on December 23. The peak reached 11,818 customers interrupted.

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

   The Company secured a total of 331 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 192 external crews and 139 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 - 126 crews
   External Overhead Line - 330 crews
   Internal Wire Down - 150 crews
   Internal Underground - 27 crews
   Internal Substation - 152 crews
   Contractor Forestry - 246 crews

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

   The Incident Commander for Rhode Island Energy did request mutual assistance from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event. On the morning of December 21, 2022, the Company requested 100-line workers to support anticipated restoration efforts.

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

   The first contact with material suppliers was on December 22.

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

PLANT#	1107	1108	1115	1120	1101 Alloc.
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGSTOWN	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC
12/23/2022	-	$909,205	-	$137,728	-

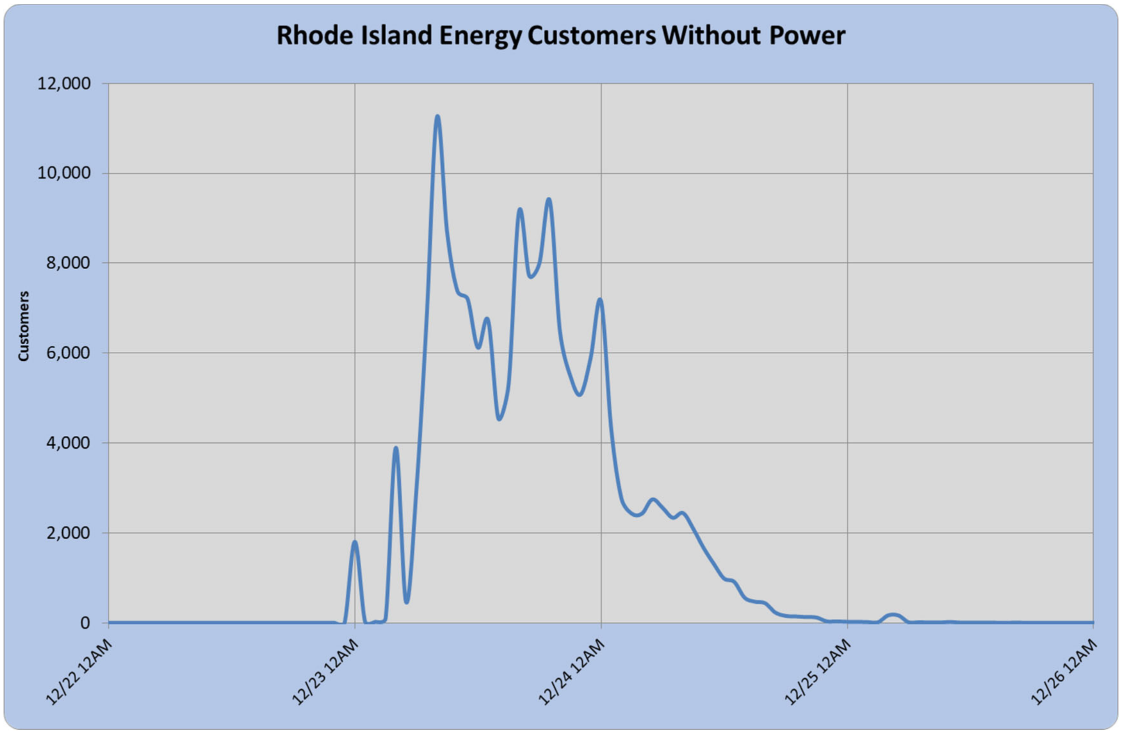
7. **Date/Time of request for external crews:**

Given the potential magnitude of the storm and forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all its regional preparation for the storm, consistent with its Emergency Response Plan. The first request for external contractor crews was at 3:30 p.m. on December 19.

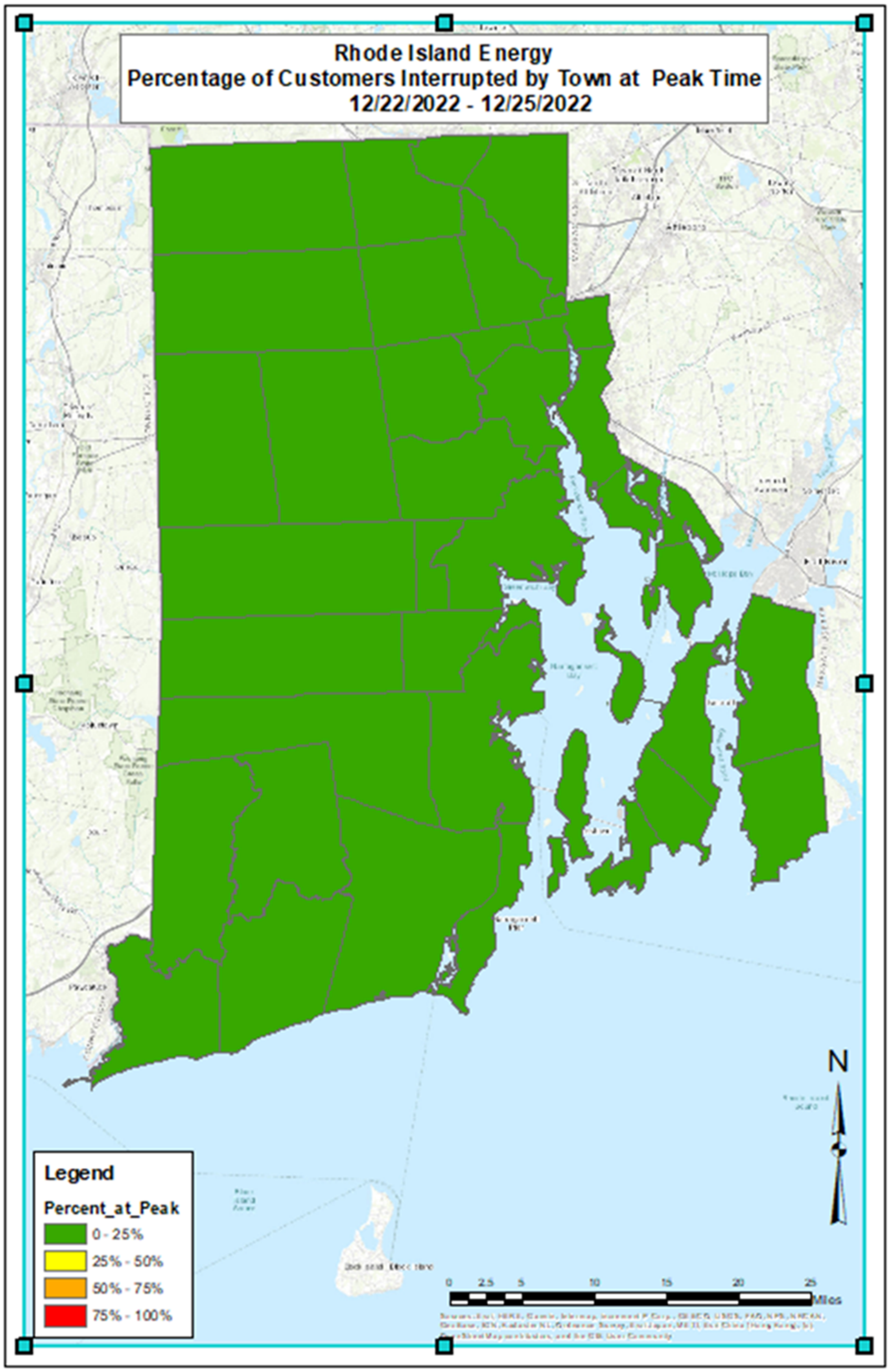
8. **Date/Time of external crew assignment:**

External crews were assigned to work around 9:00 am on December 23.

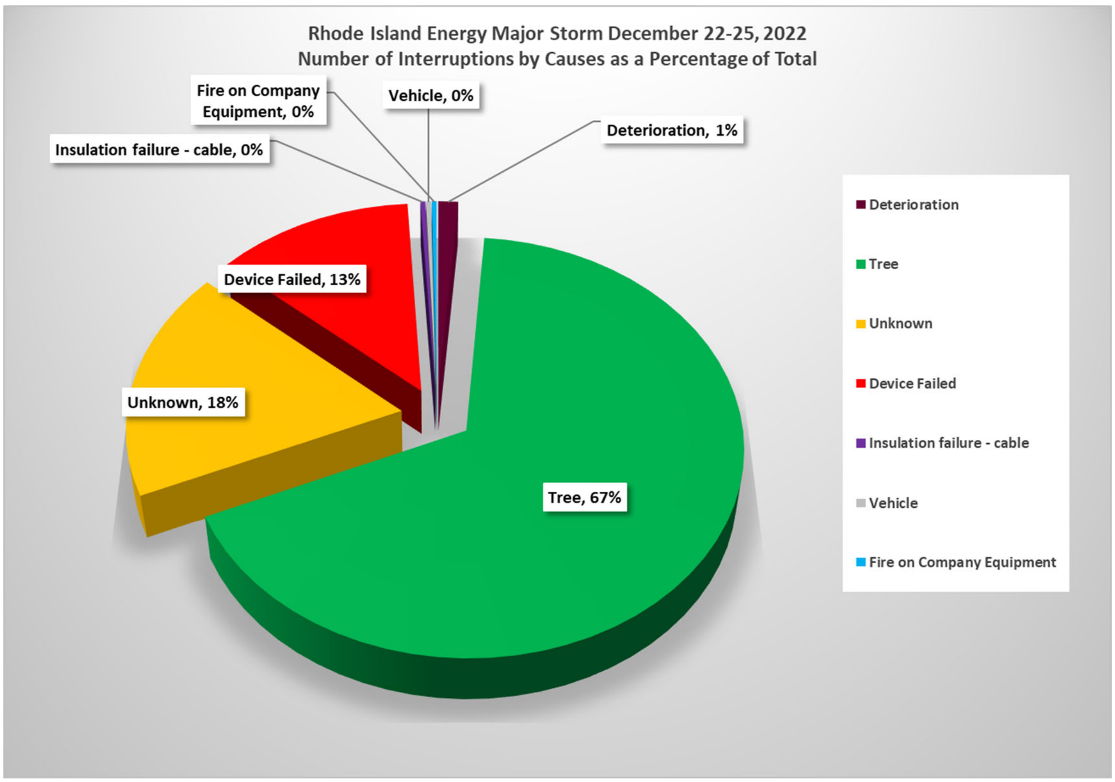
9. # of customers out of service by hour:



10. Impacted area:



11. Cause:



12. Weather impact on restoration:

The storm was a long duration weather event that resulted in moderate damage to the Company's electrical system. The storm brought heavy rain and strong wind gusts to the state, along with a sharp drop in temperatures as expected. Peak wind gusts were generally in the 40-45 mph range, with Providence experiencing a peak gust of 64 mph and 1.5 inches of rain accumulated. The Town of Tiverton was affected most heavily with approximately 81 percent of customers impacted by the event.

13. Analysis of protective device operation:

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

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

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

14. Summary of customers impacted:

December 23, 2022

On December 23, Rhode Island experienced 460 interruptions that affected 45,070 customers and 9,364,955 customer minutes of interruption. On average these interruptions resulted in 0.09 SAIFI, 18.69 minutes of SAIDI. Since a SAIDI value of 18.69 minutes exceeded the threshold value of 6.88 minutes, December 23 is qualified as a Major Event Day under the IEEE methodology.

December 24, 2022

On December 24, Rhode Island experienced 58 interruptions that affected 1,059 customers and 280,714 customer minutes of interruption. On average these interruptions resulted in 0.0021 SAIFI, 0.56 minutes of SAIDI. Since a SAIDI value of 0.56 minutes did not exceed the threshold value of 6.88 minutes, December 24 is not qualified as a Major Event Day under the IEEE methodology.

December 25, 2022

On December 25, the restoration was still ongoing, but the daily SAIDI value was very small and less than the threshold value of 6.88 minutes. December 25 is not qualified as a Major Event Day under the IEEE methodology.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were 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

April 28, 2023
Date

Rhode Island Energy– Electric Service Quality Plan – Compliance - Docket 3628 Service List Updated 06/30/2022

Name	E-mail Distribution List	Phone
The Narragansett Electric Company d/b/a **Rhode Island Energy** Leticia C. Pimentel, Esq. Robinson & Cole LLP One Financial Plaza, 14th Floor Providence, RI 02903	lpimentel@rc.com; sboyajian@rc.com; hseddon@rc.com; cobrien@pplweb.com; amarcaccio@pplweb.com; jhutchinson@pplweb.com; jscanlon@pplweb.com;	401-709-3337
Leo Wold, Esq. Division of Public Utilities & Carriers 89 Jefferson Boulevard Warwick, RI 02888 Gregory Booth, Consultant Tiffany Parenteau, Esq. Dept. of Attorney General Office	leo.wold@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov; Joseph.Shilling@dpuc.ri.gov; Tparenteau@riag.ri.gov; eullucci@riag.ri.gov; Al.contente@dpuc.ri.gov; John.bell@dpuc.ri.gov; Margaret.L.Hogan@dpuc.ri.gov;	
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Boulevard Warwick, RI 02888	Luly.massaro@puc.ri.gov; Todd.bianco@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107

JOINT PRE-FILED DIRECT TESTIMONY

OF

STEPHANIE A. BRIGGS

JEFFREY D. OLIVEIRA

AND

NATALIE HAWK

August 1, 2023

Table of Contents

I. Introduction

Stephanie A. Briggs

Q. Please state your full name and business address.

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

Q. Please state your position.

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

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Arts degree in Accounting from Bryant College. In 2004, I was hired by National Grid USA Service Company, Inc. ("National Grid Service Company") as a Senior Analyst in the Accounting Department. In this position, I was responsible for supporting the books and records of National Grid USA's ("National Grid") New York affiliate. In 2009, I was promoted to Senior Analyst in National Grid's Regulatory Accounting Group. In this capacity, I supported the accounting of regulatory assets and deferrals in accordance with the rate plans and agreements applicable to National Grid's affiliated distribution operating companies. In 2011, I was promoted to Lead Specialist for Revenue Requirements responsible for supporting New York revenue requirements. In 2017, I was promoted to Director of Revenue Requirements for New York. In July 2020, I became Director of Revenue Requirements for New England. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of the Company from National Grid (the "Acquisition") at which time I began working in my current position.

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

A. Yes. I testified before the PUC in support of the Company's filings in proceedings as follows: 2023 Renewable Energy Growth Factor Filing, Docket No. 22-04-REG, 2023 Annual Retail Rate Filing, Docket No. 23-03-EL; 2024 Gas Infrastructure, Safety and Reliability Plan, Docket No. 22-54-NG; 2024 Electric Infrastructure, Safety and Reliability Plan, Docket No. 22-53-EL; 2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG; 2022 Last Resort Service Rate Filing, Docket No. 4978; 2022 Renewable Energy Growth Factor Filing, Docket No. 22-04-REG; 2022 Annual Retail Rate Filing, Docket No. 5234; Joint Petition of National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") filed February 23, 2022 relating to the Storm Contingency Fund Replenishment, Docket No. 4686; 2021 Distribution

Adjustment Charge Filing, Docket No. 5165; 2021 Pension Adjustment Factor Filing, Docket No. 5179; 2020 Distribution Adjustment Charge Filing, Docket No. 5040; 2020 Pension Adjustment Factor Filing, Docket No. 5054; 2019 Distribution Adjustment Charge Filing, Docket No. 4955; 2019 Pension Adjustment Factor Filing, Docket No. 4958; 2018 Distribution Adjustment Charge Filing, Docket No. 4846; 2018 Pension Adjustment Factor Filing, Docket No. 4855; and again in Docket No. 4686, in support of the Joint Proposal and Settlement submitted by the Company and the Division dated September 25, 2017 pertaining to the operation of the Storm Contingency Fund. I have also submitted pre-filed testimony to the Massachusetts Department of Public Utilities on behalf of the Massachusetts Electric Company and Nantucket Electric Company as a revenue requirement witness in annual pension adjustment mechanism proceedings.

Jeffrey D. Oliveira

Q. Please state your full name and business address.

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

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

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

Q. Please describe your education and professional experience.

A. In 2000, I earned an associate degree in Business Administration from Bristol Community College in Fall River, Massachusetts. I was employed by 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. 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 in support of the Company's filings in proceedings as follows: 2023 Annual Retail Rate Filing, Docket No. 23-03-EL; 2024 Gas Infrastructure, Safety and Reliability Plan, Docket No. 22-54-NG; 2024 Electric Infrastructure, Safety and Reliability Plan, Docket No. 22-53-EL; 2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG; 2022 Last Resort Service Rate Filing, Docket No. 4978; 2023 Renewable Energy Growth Factor Filing, Docket No. 23-24-REG; 2022 Annual Retail Rate Filing, Docket No. 5234; Joint Petition of National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") filed February 23, 2022 relating to the Storm Contingency Fund Replenishment, Docket No. 4686; 2021 Distribution Adjustment Charge Filing, Docket No. 5165; 2021 Pension Adjustment Factor Filing, Docket No. 5179; 2020 Distribution Adjustment Charge Filing, Docket No. 5040; 2020 Pension Adjustment Factor Filing, Docket No. 5054; 2019 Distribution Adjustment Charge Filing, Docket No. 4955; 2019 Pension Adjustment Factor Filing, Docket No. 4958; 2018 Distribution Adjustment Charge Filing, Docket No. 4846; 2018 Pension Adjustment Factor Filing, Docket No. 4855; and again in Docket No. 4686, in support of the Joint Proposal and Settlement submitted by the Company and the Division dated September 25, 2017 pertaining to the operation of the Storm Contingency Fund. I have also submitted pre-filed testimony to the Massachusetts Department of Public Utilities on behalf of the Company's affiliates, Massachusetts Electric Company, and Nantucket Electric Company, as a revenue requirement witness in annual pension adjustment mechanism proceedings.

Natalie Hawk

Q. Please state your full name and business address.

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

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

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

Q. Please describe your education and professional experience

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

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

A. Yes. I testified before the PUC in support of the Company's FY 2024 Gas Safety and Reliability Plan, Docket No. 22-54-NG and 2024 Electric Infrastructure, Safety and Reliability Plan, Docket No. 22-53-EL.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric ISR factor, for effect on April 1, 2022. That factor was based on a projected FY 2023 ISR revenue requirement of $49,721,324 for the estimated operation and maintenance ("O&M") work associated with the Company's vegetation management ("VM") and inspection and maintenance ("I&M") programs for the Company's FY ended March 31, 2023, on the estimated ISR plant additions during the Company's FYs ended March 31, 2023 and 2022, and on the actual ISR additions during the Company's Fiscal Years ended March 31, 2018, 2019, 2020, and 2021 which were incremental to the levels reflected in rate base in the Company's last base rate case (Docket No.4770). On September 1, 2018, new distribution base rates as approved in Docket No. 4770 became effective. The revenue requirements on actual ISR additions made from FY 2012 through FY 2017 plus forecasted ISR additions for FY 2018, FY 2019, and a portion of FY 2020 were included in these new base rates. Thus, the purpose of our testimony is to present an updated FY 2023 Electric ISR revenue requirement associated with actual FY 2023 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2023 incremental to the level of investment assumed in Docket No. 4770, and actual tax deductibility percentages, tax gains and losses on retirements and NOL utilization for FY 2022, an adjustment for the DG project review and a hold harmless adjustment credit.

The updated FY 2023 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, 2023.

As shown on Attachment SAB/JDO-1, Page 1 at Line 19, the updated FY 2023 ISR revenue requirement collectible through the Company's ISR factor for the FY 2023 period, including updated tax deductibility adjustments to the FY 2022 revenue requirement, totals $40,031,046. This is a decrease of $9,690,279 from the projected FY 2023 Electric ISR revenue requirement of $49,721,324, previously approved by the PUC in this docket. This decrease is primarily attributable to (1) a decrease in the actual effective FY 2023 property tax rate compared with the projected effective FY 2023 property tax rate in the FY 2023 ISR Plan; (2) a decrease in the FY 2022 and FY 2023 revenue requirement on a lower level of capital investment; and (3) a reduction to the revenue requirement for the results of the Distributed Generation (DG) project review as described in the testimony of Ms. Gooding. The increase to the FY 2023 capital revenue requirement related to the sale transaction has been offset by a reduction to the FY 2023 total revenue requirement as a hold harmless adjustment.

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

A. At this time, it is projected that the Company will earn taxable income and utilize prior years' tax net operating losses (NOL) in FY 2023. In Docket No. 4770, the accumulated deferred income taxes included in rate base assumed estimated NOL utilization. Therefore, the difference between the newly estimated NOL utilization and the NOL utilization assumed in base rates was included in the vintage year FY 2023 ISR Plan revenue requirement based on the most recent estimate of FY 2023 tax deductibility. Actual tax deductibility percentages for FY 2023 plant additions will not be known until the Company files its FY 2023 income tax return in December of this year.

Consequently, the actual tax deductibility percentages for FY 2023 plant additions continues to be an estimate, although updated, in this reconciliation. The actual deductibility percentage for FY 2023 will be updated in the Company's FY 2024 Electric ISR Reconciliation filing and will generate a true-up adjustment in that filing.

Q. Are there any schedules attached to your testimony?

A. Yes, we are sponsoring the following Attachments:

- Attachment SAB/JDO-1 FY 2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Revenue Requirement
- Attachment NH-1 FY 2023 Hold Harmless Adjustment

II. <u>Electric ISR FY2023 Revenue Requirement</u>

Q. Did the Company calculate the updated FY 2023 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2022 ISR factor reconciliation?

A. Yes, the Company calculated the updated FY 2023 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions. Similar to the FY 2022 filing, the calculation incorporates the approved weighted average cost of capital and depreciation rates from Docket No. 4770 and known tax deductibility percentages, tax gains and losses on retirements and NOL utilization for FY 2022.

The updated FY 2023 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, 2022. A detailed description of the revenue requirement calculation employed can be found in the revenue requirement testimony included in the Company's FY 2023 ISR Plan Proposal filing in this docket. For brevity, we 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 SAB/JDO-1; and 3) a summary of FY 2022 revenue requirement income tax true-up shown on Page 1 of Attachment SAB/JDO-1 related to the update for the tax deductibility percentages, tax gains and losses on retirements and NOL utilization.

Q. Please summarize the change in the FY 2023 ISR revenue requirement proposed in this reconciliation filing as compared to the FY 2023 revenue requirement effective April 1, 2022, which was based on projected capital additions approved in the FY 2022 and FY 2023 ISR Plans.

A. As shown in Attachment SAB/JDO-1, Page 1, Line 20, column (c), the overall FY 2023 revenue requirement decrease is $9,690,279, which is the net impact of:

(1) a $2.1 million decrease in the FY 2023 revenue requirement on vintage FY 2022 ISR capital additions mainly driven by the actual FY 2022 capital additions compared to forecasted FY 2022 additions, in addition to the FY 2022 income tax deductibility

update; (2) a $1.0 million decrease in the FY 2023 revenue requirement on vintage FY 2023 ISR capital additions mainly caused by $11.7 million lower capital investment placed into service compared to the amount approved in the FY 2023 Plan; (3) a $2.9 million decrease in the FY 2023 property tax recovery adjustment mainly driven by the lower actual tax rate in FY 2023 compared to the previous filed FY 2023 Plan; (4) an increase of $0.03 million due to the true-up of FY 2022 revenue requirement to reflect actual tax deductibility as described in detail later in this testimony; (5) a net reduction to the FY 2023 revenue requirement of $0.3 million for FY 2018 through FY 2021 capital investments mainly related to the DG project review and (6) a $0.6 million increase in O&M expense compared to the approved FY 2023 plan. Additionally, the FY 2023 revenue requirement was decreased by a reduction for the tax hold harmless adjustment of $0.8 million and a $3.2 million reduction for the impact of the DG project review for FY 2018 through FY 2022 capital investments.

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

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

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

Q. Please describe the calculation of the excess deferred income tax amounts.

A. As a result of the implementation of new base rates pursuant to Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR capital investments was rolled into base rates effective at that date. Consequently, the ISR revenue requirements after FY 2019 reflect the revenue requirement of incremental ISR investments of FY 2018 and after. Among the vintage years, only FY 2018 incremental ISR investment created excess deferred tax. The excess deferred income taxes are calculated on Line 27, Page 2 of Attachment SAB/JDO-1. 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).

Q. How was the Electric ISR revenue requirement revised for the change in the bonus depreciation rules resulting from the 2017 Tax Cuts and Job Act ("2017 Tax Act")?

A. Bonus depreciation, sometimes known as first year bonus depreciation, is an accelerated tax depreciation method that was first established in 2002 as an economic stimulus to incent United States corporations to increase capital investments. Bonus depreciation allows companies to take an immediate tax deduction for some portion of certain qualified capital investments based on the bonus depreciation rates in effect for that year of investment. Bonus depreciation rates have ranged from a high of 100 percent in some years to as low as 30 percent for calendar year 2019, as specified in the tax laws prior to the passage of the 2017 Tax Act. Pursuant to those prior tax laws, bonus depreciation was set to expire at the end of calendar year 2019. However, the 2017 Tax Act changed the rules for bonus depreciation for certain capital investments, including ISR-eligible investments, effective September 28, 2017. Based on the 2017 Tax Act, property acquired prior to September 28, 2017 and placed in service during tax years beginning after December 31, 2017 are allowed bonus depreciation.

As indicated in the Company's FY 2023 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 2023 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2023 investments.

Q. Are there any updates to the FY 2022 revenue requirement reflected in the FY 2023 Electric ISR Reconciliation?

A. Yes. The Company filed its FY 2022 Electric ISR Reconciliation Compliance Filing on September 24, 2022. However, it had not filed its FY 2022 income tax return until later that year in the month of December. As a result, the Company used certain tax assumptions, and the Company has revised its vintage FY 2022 revenue requirement to reflect the following updates on Attachment SAB/JDO-1, Pages 17, 18, 19 and 23: (1) actual capital repairs deduction rate of 29.67 percent as shown on Attachment SAB/JDO-1, Page 18, Line 2; (2) actual tax loss on retirements of $6,103,955 as shown on Attachment SAB/JDO-1 Page 18, Line 24; and (3) actual NOL utilization of $730,905 as shown on Attachment SAB/JDO-1 Page 23, Line 11, column (e). The net result of these tax deductibility updates is an increase to the FY 2022 ISR revenue requirement of $31,472, as shown on Attachment SAB/JDO-1, Page 1 at Line 13.

Q. Please summarize the updated FY 2023 ISR revenue requirement.

A. As shown on Page 1 of Attachment SAB/JDO-1, the Company's FY 2023 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's VM activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. The description of these elements and the related amounts are supported by the direct testimony and supporting attachments of Ms. Nicole Gooding. Line 4 reflects the actual FY 2023 revenue requirement related to O&M expenses of $13,731,126.

As shown on Page 1, at Line 14 of Attachment SAB/JDO-1, the FY 2023 revenue requirement associated with the Company's actual capital investment totals $30,275,153. As previously noted, the total FY 2023 capital investment component of revenue requirement includes (1) FY 2023 revenue requirement on vintages FY 2018 through FY 2023 ISR capital investments above or below the level of capital investment reflected in base distribution rates in Docket No. 4770; (2) the FY 2023 property tax recovery mechanism component; and (3) the FY 2022 revenue requirement true-up for changes to previously estimated tax depreciation expense and NOL position to align with the Company's FY 2022 tax return.. The total actual FY 2023 ISR Plan revenue requirement for both O&M expenses and capital investment of $44,006,279 is shown on Line 15. Additionally, the FY 23 Revenue Requirement is reduced by the Hold Harmless adjustment on Line 16 and the DG Project Review adjustment on Line 18, for a net FY 2023 Revenue Requirement of $40,031,046 on Line 19.

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

A. Page 1 of Attachment SAB/JDO-1 summarizes the individual components of the updated FY 2023 ISR revenue requirement. Page 1, Column (a) reflects the approved FY 2023 Electric ISR Plan revenue requirement on projected VM and I&M program costs and incremental ISR capital investment as well as the projected FY 2023 property tax recovery adjustment. Page 1, Column (b) represents (1) the O&M components for FY 2023; (2) FY 2023 ISR revenue requirements for incremental FY 2018 through FY 2023 ISR investments – not included in the Company's base rates in Docket No. 4770– and as supported with detailed calculations on Attachment SAB/JDO-1, Pages 2, 5, 10, 13, 17 and 20; (3) FY 2023 property tax adjustment on incremental capital not included in the Company's base rates in Docket No. 4770; (4) the reconciliation on Line 13 of the approved FY 2022 ISR revenue requirement for vintage FY 2022 plant additions with the actual vintage FY 2022 revenue requirement on those investments related to tax deductibility updates; (5) the hold harmless adjustment related to the sale transaction; and (6) the DG project review adjustment. As previously discussed, this reconciliation in item (4) is necessary because the actual level of tax deductibility on FY 2022 investments was not known when the Company filed the FY 2022 ISR reconciliation and FY 2023 ISR Plan proposals. A detailed calculation of the updated FY 2022 revenue requirement is presented on page 17 of Attachment SAB/JDO-1.

Q. Has the Company provided support for the actual level of FY 2023 ISR-eligible plant investments?

A. Yes. The description of the FY 2023 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR mechanism are supported by the direct testimony and supporting attachment of Ms. Gooding. The ultimate revenue requirement on the ISR eligible plant additions equals the return on the investment (i.e., average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental ISR eligible plant additions for this purpose are intended to represent the net change in rate base for electric infrastructure investments, since the establishment of the Company's ISR mechanism effective April 1, 2011 and are defined as capital additions plus cost of removal, less annual depreciation expense included in the Company's rates, net of depreciation expense attributable to general plant. As discussed in the testimony of Ms. Gooding, the actual ISR eligible plant additions for FY 2023 totals $94.8 million associated with the Company's FY 2023 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 2023 revenue requirement, the lesser of these items was actual discretionary capital additions of $53,320,145, as shown on Attachment SAB/JDO-1, Page 32, Line 13, column (a), of which $53,320,145 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 2023 revenue requirement, associated with the Company's actual FY 2018 through FY 2023 ISR eligible plant investments, totals $40,031,046. This amount includes the updated FY 2023 O&M components and revenue requirement on FY 2018 through FY 2023 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 2022 ISR revenue requirements on vintage FY 2022 investments with the actual FY 2022 income tax deductibility on those investments.

Q. What are the impacts of the sale of the Company to PPL Rhode Island on the FY 2023 Electric ISR revenue requirement calculations?

A. On May 25, 2022, PPL Rhode Island, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of Company from National Grid (the "Acquisition"). The Acquisition was treated as an asset acquisition for tax purposes under Internal Revenue Code (IRC) §338(h)(10) ("the §338 election"), which resulted in the recognition of all book and tax timing differences and the reversal of the related deferred tax assets and liabilities in FY 2023. In addition, the Company utilized all its available Net Operating Losses ("NOL") to offset taxable income generated from the sale, which resulted in the reversal of all NOL-related deferred tax assets in FY 2023. The reversal of all deferred tax assets and liabilities, including NOL deferred tax assets, reduced net deferred tax liabilities which increased the ISR rate base in the vintage revenue requirement calculations by $9,225,192 for FY 2023. Consequently, the increase in rate base ultimately increases the return on rate base recoverable through the ISR mechanism. The expected impact to the FY 2023 Electric ISR Reconciliation revenue requirement would be an increase of approximately $759,233 in FY 2023 as shown on Attachment SAB/JDO-1, Page 1, Line 16 and shown in detail on Attachment NH-1.

Q. How does the Company propose to address the above increases to the revenue requirements on the FY 2023 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. These cash tax benefits will be shared with the customer in the form of revenue credits to offset the increase in revenue requirements from the increase in rate base because of the elimination of deferred taxes from the Acquisition. Consequently, the Company is proposing to reduce the FY 2023 revenue requirements by the calculated hold harmless amounts as shown on Attachment SAB/JDO-1, Page 1, Line 16.

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

A. Because of the §338 election, the Acquisition resulted in the reversal of book and tax timing differences and the related deferred taxes. In addition, tax depreciation starts over on a new tax basis equal to net book value on the date of the Acquisition. To reflect these

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

impacts of the Acquisition, the calculations of the FY 2023 rate base and revenue requirement for the vintage plan years FY 2018 through FY 2023 were separated into two columns in Attachment SAB/JDO-1, Pages 2,5,10,13,17 and 20. The first FY 2023 column labeled as "NG, 4/1/22-5/24/22", reflects the 54 days of National Grid ownership. 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 where the deferred taxes under National Grid's ownership are reversed and the tax basis becomes equal to net book basis, causing the book and tax timing difference and tax depreciation to start over.

Q. Please describe the adjustment to reduce the FY 2023 revenue requirement for the DG project review.

A. As described in the pre-filed testimony of Ms. Gooding, the Company has decided to remove the remaining plant additions associated with DG projects from the revenue requirement until a review of each project is completed. The capital additions in the FY 2023 actuals included the adjustment for DG projects that were placed in service during FY 2023. Additionally, the FY 2023 revenue requirement has been reduced to reflect the FY 2018 through FY 2022 revenue requirement associated with the DG projects that have been removed as shown on Attachment SAB/JDO-1, Page 1, Line 18, column (b) and Attachment SAB/JDO-1, Page 33, Line 25.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

Index of Attachments

Attachment SAB/JDO-1	FY 2023 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Revenue Requirement Summary and Calculation
Attachment NH-1	FY 2023 Hold Harmless Adjustment Credit

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

Line No.		Approved Fiscal Year 2023 (a)	Actual Fiscal Year 2023 (b)	Variance Fiscal Year 2023 (c)=(b)-(a)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$11,875,000	$12,748,094	$873,094
2	Current Year Inspection & Maintenance (I&M)	$1,015,000	$712,372	($302,628)
3	Current Year Other Programs	$249,000	$270,660	$21,660
4	**Total O&M Expense Component of Revenue Requirement**	**$13,139,000**	**$13,731,126**	**$592,126**
	Capital Investment:			
5	Actual 2023 Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,946,604	$1,805,484	($141,120)
6	Actual 2023 Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$3,965,256	$4,042,712	$77,456
7	Actual 2023 Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,692,039	$5,419,949	($272,090)
8	Actual 2023 Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$8,510,363	$8,514,586	$4,224
9	Actual 2023 Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$7,030,129	$4,912,322	($2,117,807)
10	Actual 2023 Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base	$3,944,106	$2,920,999	($1,023,107)
11	Subtotal	$31,088,497	$27,616,054	($3,472,444)
12	FY 2023 Property Tax Recovery Adjustment	$5,493,827	$2,627,628	($2,866,199)
13	True-Up for FY 2022 (Income Tax)		$31,472	$31,472
14	**Total Capital Investment Component of Revenue Requirement**	**$36,582,324**	**$30,275,153**	**($6,307,171)**
15	**Total Fiscal Year Revenue Requirement**	**$49,721,324**	**$44,006,279**	**($5,715,045)**
16	**Per Tax Hold Harmless Adjustment per Attachment NH-1**		(759,233)	($759,233)
17	**Total Net Revenue Requirement**	**$49,721,324**	**$43,247,046**	**($6,474,278)**
18	**Adjustment for DG Project review (FY 18 - FY 22 revenue requirement)**		**($3,216,001)**	($3,216,001)
19	**Total Net Revenue Requirement with DG review adjustment**	**$49,721,324**	**$40,031,046**	**($9,690,279)**
20	**Incremental Fiscal Year Rate Adjustment**		**($9,690,279)**	

Column/Line Notes:

Col (a)	Docket No. 5098, FY 2022 Electric ISR Plan, Revised Section 5: Attachment 1C, Page 1 of 29, Column (b)
Col (b)	
1	Vegetation Management, Attachment NAG-1, Table 10
2	Other Operations and Maintenance, Attachment NAG-1, Table 11
3	Other Operations and Maintenance, Attachment NAG-1, Table 11
4	Sum of Lines 1 through 3
5	Page 2 of 33, Line 40 column (f) + (g)
6	Page 5 of 33, Line 42 column (e) + (f)
7	Page 10 of 33, Line 39 column (d) + (e)
8	Page 13 of 33, Line 40 column (c) + (d)
9	Page 17 of 33, Line 39 column (b) + (c)
10	Page 20 of 33, Line 39 column (a) + (b)
11	Sum of Lines 5 through 10
12	Page 28 of 33, Line 85, Column (u) x 1,000
13	Page 17 of 33, Line 41, Column (a)
14	Sum of Lines 11 through 13
15	Line 4 + Line 14
16	Attachment NH-1, Page 1, Line 23
17	Line 15 + Line 16
18	Page 33 of 33, Line 25
19	Line 17 + Line 18
20	Line 19 Col (b) - Line 19 Col (a)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Fiscal Year 2023 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)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*			$1,828,121						
	Discretionary Capital									
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256						
3	Total Allowed Capital Included in Rate Base	Page 23 of 33, Line 4(a)		$16,466,377	$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		$16,466,377	$0	$0	$0	$0	$0	$0
5	Retirements	Page 23 of 33 , Line 10 ,Col (a)		($5,245,072)	$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		$21,711,449	$21,711,449	$21,711,449	$21,711,449	$21,711,449	$21,711,449	$21,711,449
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3		$16,466,377	$0	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$16,466,377	$16,466,377	$16,466,377	$16,466,377	$16,466,377	$16,466,377	$16,466,377
10	Cost of Removal	Page 23 of 33 , Line 7 ,Col (a)		$1,693,009	$0	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$18,159,386**	**$18,159,386**	**$18,159,386**	**$18,159,386**	**$18,159,386**	**$18,159,386**	**$18,159,386**
	Deferred Tax Calculation:									
12	Composite Book Depreciation Rate		1/	3.40%	3.26%	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 33, Line 29; then = Page 3 of 33, Column (e)		$13,098,604	$527,752	$488,128	$451,575	$417,654	$57,161	$496,115
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$13,098,604	$13,626,356	$14,114,484	$14,566,059	$14,983,713	$15,040,874	
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/							$496,115
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12	2/	$369,095	$707,793	$686,082	$686,082	$686,082	$101,503	$584,579
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$369,095	$1,076,888	$1,762,970	$2,449,051	$3,135,133	$3,236,636	$3,821,215
21	Cumulative Book / Tax Timer	Columns (a) through (f): Line 17 - Line 20, Then Line 18 - Line 20		$12,729,509	$12,549,468	$12,351,514	$12,117,008	$11,848,580	$11,804,238	($3,325,100)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (f)	3/							$3,236,636
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22								($88,464)
24	Effective Tax Rate		4/	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		$2,673,197	$2,635,388	$2,593,818	$2,544,572	$2,488,202	$2,478,890	($18,577)
26	Less: FY 2018 Federal NOL	Year 1 = Page 23 of 33 , 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
27	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,342,963	$1,342,963	$1,342,963	$1,342,963	$1,342,963	$1,342,963	$1,342,963
28	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 27		$1,017,662	$979,853	$938,283	$889,036	$832,667	$823,355	$1,324,386
	Rate Base Calculation:									
29	Cumulative Incremental Capital Included in Rate Base	Line 11		$18,159,386	$18,159,386	$18,159,386	$18,159,386	$18,159,386	$18,159,386	$18,159,386
30	Accumulated Depreciation	-Line 20		($369,095)	($1,076,888)	($1,762,970)	($2,449,051)	($3,135,133)	($3,236,636)	($3,821,215)
31	Deferred Tax Reserve	-Line 28		($1,017,662)	($979,853)	($938,283)	($889,036)	($832,667)	($823,355)	($1,324,386)
32	Year End Rate Base before Deferred Tax Proration	Sum of Lines 29 through 31		$16,772,630	$16,102,645	$15,458,134	$14,821,298	$14,191,586	$14,099,396	$13,013,785
	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/	$8,386,315	$16,437,637	$15,780,389	$15,139,716	$14,506,442	$13,602,686	$13,602,686
34	Proration Adjustment	Page 4 of 33, Line 41				($1,784)	($2,114)	($2,420)	($1,197)	($1,197)
35	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$8,386,315	$16,437,637	$15,778,605	$15,137,602	$14,504,023	$13,601,489	$13,601,489
36	Pre-Tax ROR	Page 31 of 33, Line 35		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/	$690,194	$1,352,818	$1,298,579	$1,245,825	$1,193,681	$165,610	$953,792
39	Book Depreciation	Line 19		$369,095	$707,793	$686,082	$686,082	$686,082	$101,503	$584,579
40	**Annual Revenue Requirement**	Line 38 + Line 39		**$1,059,288**	**$2,060,611**	**$1,984,661**	**$1,931,906**	**$1,879,763**	**$267,113**	**$1,538,372**

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 2023 Electric ISR Revenue Requirement 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 33, Line 3		$16,466,377		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%					
3	Capital Repairs Deduction	Line 1 * Line 2		$1,481,974	NG MACRS basis:	Line 22, Column (a)		$7,310,591	
4		`						Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$16,466,377	FY Mar-2018	3.750%		$274,147	$13,098,604
7	Less Capital Repairs Deduction	- Line 3		($1,481,974)	FY Mar-2019	7.219%		$527,752	$13,626,355
8	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7		$14,984,403	FY Mar-2020	6.677%		$488,128	$14,114,484
9	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2021	6.177%		$451,575	$14,566,059
10	Plant Eligible for Bonus Depreciation	Line 8 * Line 9		$14,984,403	FY Mar-2022	5.713%		$417,654	$14,983,713
11	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%	FY Mar-2023 (Apr-May 2022)	5.285%	0.782%	$57,161	$15,040,874
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)		$16,466,377	
15	Total Bonus Depreciation Rate	Line 11 + Line 12 + Line 13 + Line 14		51.21%	Cumulative Book Depreciation	- Page 2 of 33, Line 20, Col (f)		($3,236,636)	
16	Bonus Depreciation	Line 10 * Line 15		$7,673,812	PPL MACRS basis:	Line 14(e) + Line 15(e)		$13,229,741	
17									
18	Remaining Tax Depreciation				Mar-2023 (Jun-Mar 2023)	3.750%		$496,115	$496,115
19	Plant Additions	Line 1		$16,466,377	Mar 2024	7.219%		$955,055	$1,451,170
20	Less Capital Repairs Deduction	Line 3		$1,481,974	Mar 2025	6.677%		$883,350	$2,334,520
21	Less Bonus Depreciation	Line 16		$7,673,812	Mar 2026	6.177%		$817,201	$3,151,721
22	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 19 - Line 20 - Line 21		$7,310,591	Mar 2027	5.713%		$755,815	$3,907,536
23	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar 2028	5.285%		$699,192	$4,606,728
24	Remaining Tax Depreciation	Line 22 * Line 23		$274,147	Mar 2029	4.888%		$646,670	$5,253,398
25					Mar 2030	4.522%		$598,249	$5,851,647
26	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662	Mar 2031	4.462%		$590,311	$6,441,958
27	Cost of Removal	Page 2 of 33, Line 10		$1,693,009	Mar 2032	4.461%		$590,179	$7,032,137
28					Mar 2033	4.462%		$590,311	$7,622,448
29	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 16, 24, 26, and 27		$13,098,604	Mar 2034	4.461%		$590,179	$8,212,627
30					Mar 2035	4.462%		$590,311	$8,802,938
31					Mar 2036	4.461%		$590,179	$9,393,116
32					Mar 2037	4.462%		$590,311	$9,983,427
33					Mar 2038	4.461%		$590,179	$10,573,606
34					Mar 2039	4.462%		$590,311	$11,163,917
35					Mar 2040	4.461%		$590,179	$11,754,096
36					Mar 2041	4.462%		$590,311	$12,344,407
37					Mar 2042	4.461%		$590,179	$12,934,586
38					Mar 2043	2.231%		$295,156	$13,229,741
39						92.78%		$13,229,741	
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 2023 Electric ISR Revenue Requirement 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)
1	Book Depreciation	Col (a): Page 2 of 33, Line 19, column (e); Col (b): Page 2 of 33, Line 19, columns (f) and (g); Col (c): Page 2 of 33, Line 19, column (h)	$686,082	$686,082
2	Bonus Depreciation		$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 3 of 33, Line 10, column, (e); Col (b): - Page 3 of 33, Sum of Lines 11 and 18, column (e); Col (c): - Page 3 of 33, Line 19, column, (e)	($417,654)	($553,276)
4	FY18 tax (gain)/loss on retirements		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$268,428	$132,806
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$56,370	$27,889
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction			
9	Cost of Removal			
10	Book/Tax Depreciation Timing Difference at 3/31/2017			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$56,370	$27,889
15	Net Operating Loss		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$56,370	$27,889
	Allocation of FY 2018 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$268,428	$132,806
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$268,428	$132,806
20	Total FY 2018 Federal NOL			
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$56,370	$27,889

Line No.		(d)	(e)	(f)	(g)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23
26	April	30	91.78%	$4,311	$2,133
27	May	31	83.29%	$3,912	$1,936
28	June	30	75.07%	$3,526	$1,745
29	July	31	66.58%	$3,127	$1,547
30	August	31	58.08%	$2,728	$1,350
31	September	30	49.86%	$2,342	$1,159
32	October	31	41.37%	$1,943	$961
33	November	30	33.15%	$1,557	$770
34	December	31	24.66%	$1,158	$573
35	January	31	16.16%	$759	$376
36	February	28	8.49%	$399	$197
37	March	31	0.00%	$0	$0
38	Total	365		$25,765	$12,748
39	Deferred Tax Without Proration	Line 25		$56,370	$27,889
40	Average Deferred Tax without Proration	Line 25 * 50%		$28,185	$13,945
41	Proration Adjustment	Line 38 - Line 40		($2,420)	($1,197)

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Fiscal Year 2023 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)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*			$6,261,278					
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 23 of 33, Line 4(b)		$31,748,054	$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)		$31,748,054	$0	$0	$0	$0	$0
5	Retirements	Page 23 of 33 , Line 10 ,Col (b)		($10,649,479)	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$42,397,533	$42,397,533	$42,397,533	$42,397,533	$42,397,533	$42,397,533
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3, Column (a)		$31,748,054	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054
10	Cost of Removal	Page 23 of 33 , Line 7 ,Col (b)		$361,723					
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$32,109,777**	**$32,109,777**	**$32,109,777**	**$32,109,777**	**$32,109,777**	**$32,109,777**
	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%
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 33, Line 28 Then = Page 6 of 33 Column (e)		$9,877,791	$1,776,194	$1,642,838	$1,519,816	$207,959	$1,006,480
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$9,877,791	$11,653,985	$13,296,823	$14,816,638	$15,024,597	
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/						$1,006,480
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$691,080	$1,339,762	$1,339,762	$1,339,762	$198,211	$1,141,551
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$691,080	$2,030,842	$3,370,604	$4,710,366	$4,908,577	$6,050,128
21	Cumulative Book / Tax Timer	Columns (a) through(e): Line 17 - Line 20, Then Line 18 - Line 20		$9,186,711	$9,623,143	$9,926,219	$10,106,272	$10,116,020	($5,043,648)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (e)	3/						$4,908,577
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22							($135,070)
24	Effective Tax Rate			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		$1,929,209	$2,020,860	$2,084,506	$2,122,317	$2,124,364	($28,365)
26	Add: FY 2019 Federal NOL incremental utilization	Page 23 of 33 , Line 15 ,Col (b)	3/	$991,622	$991,622	$991,622	$991,622	$991,622	$0
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$2,920,831	$3,012,482	$3,076,128	$3,113,939	$3,115,986	($28,365)
	Rate Base Calculation:								
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$32,109,777	$32,109,777	$32,109,777	$32,109,777	$32,109,777	$32,109,777
29	Accumulated Depreciation	-Line 20		($691,080)	($2,030,842)	($3,370,604)	($4,710,366)	($4,908,577)	($6,050,128)
30	Deferred Tax Reserve	-Line 27		($2,920,831)	($3,012,482)	($3,076,128)	($3,113,939)	($3,115,986)	$28,365
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$28,497,866	$27,066,453	$25,663,045	$24,285,472	$24,085,214	$26,088,014
	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/	$14,248,933	$27,782,160	$26,364,749	$24,974,259	$25,186,743	$25,186,743
33	Proration Adjustment	Page 7 of 33, Line 43		$0	$0	$0	($522)	($959)	($959)
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$14,248,933	$27,782,160	$26,364,749	$24,973,737	$25,185,784	$25,185,784
35	Pre-Tax ROR	Page 31 of 33, Line 35		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/	$1,172,687	$2,286,472	$2,169,819	$2,055,339	$306,659	$1,766,131
38	Book Depreciation	Line 19		$691,080	$1,339,762	$1,339,762	$1,339,762	$198,211	$1,141,551
39	Annual Revenue Requirement	Line 37 + Line 38		$1,863,767	$3,626,234	$3,509,581	$3,395,101	$504,871	$2,907,681
40	Revenue Requirement of Plant	Year 1 = Line 39*7/12, Then = Line 39		$1,087,197	$3,626,234	$3,509,581	$3,395,101	$504,871	$2,907,681
41	Revenue Requirement of Intangible	Page 8 of 33, Line 34, Column (l) ~ (aa)		$434,302	$705,779	$655,914	$617,127	$81,808	$548,352
42	**Revenue Requirement**	Line 40 + Line 41		**$1,521,500**	**$4,332,013**	**$4,165,495**	**$4,012,227**	**$586,679**	**$3,456,033**

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 2023 Electric ISR Revenue Requirement 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 33, Line 3		$31,748,054		20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.68%					
3	Capital Repairs Deduction	Line 1 * Line 2		$3,073,236	MACRS basis:	Line 22, Column (a)		$24,604,428	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$31,748,054	FY Mar-2019	3.750%		$922,666	$9,877,791
7	Plant Additions			$0	FY Mar-2020	7.219%		$1,776,194	$11,653,985
8	Less Capital Repairs Deduction	Line 3		$3,073,236	FY Mar-2021	6.677%		$1,642,838	$13,296,822
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$28,674,818	FY Mar-2022	6.177%		$1,519,816	$14,816,638
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	FY Mar-2023 (Apr-May 2022)	5.713%	0.85%	$207,959	$15,024,597
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$28,674,818					
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)		$31,748,054	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		14.20%	Cumulative Book Depreciation	- Page 5 of 33, Line 20, Col (e)		($4,908,577)	
15	Bonus Depreciation	Line 11 * Line 14		$4,070,390	PPL MACRS basis:	Line 13(e) + Line 14(e)		$26,839,477	
16									
17	Remaining Tax Depreciation				FY Mar-2023 (Jun-Mar 2023)	3.750%		$1,006,480	$1,006,480
18	Plant Additions	Line 1		$31,748,054	Mar-2024	7.219%		$1,937,542	$2,944,022
19	Less Capital Repairs Deduction	Line 3		$3,073,236	Mar-2025	6.677%		$1,792,072	$4,736,094
20	Less Bonus Depreciation	Line 15		$4,070,390	Mar-2026	6.177%		$1,657,874	$6,393,969
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$24,604,428	Mar-2027	5.713%		$1,533,339	$7,927,308
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2028	5.285%		$1,418,466	$9,345,774
23	Remaining Tax Depreciation	Line 21 * Line 22		$922,666	Mar-2029	4.888%		$1,311,914	$10,657,688
24					Mar-2030	4.522%		$1,213,681	$11,871,369
25	FY19 (Gain)/Loss incurred due to retirements	Per Tax Department	3/	$1,449,776	Mar-2031	4.462%		$1,197,577	$13,068,946
26	Cost of Removal	Page 5 of 33, Line 10		$361,723	Mar-2032	4.461%		$1,197,309	$14,266,255
27					Mar-2033	4.462%		$1,197,577	$15,463,833
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$9,877,791	Mar-2034	4.461%		$1,197,309	$16,661,142
29					Mar-2035	4.462%		$1,197,577	$17,858,719
30					Mar-2036	4.461%		$1,197,309	$19,056,028
31					Mar-2037	4.462%		$1,197,577	$20,253,606
32					Mar-2038	4.461%		$1,197,309	$21,450,915
33					Mar-2039	4.462%		$1,197,577	$22,648,492
34					Mar-2040	4.461%		$1,197,309	$23,845,801
35					Mar-2041	4.462%		$1,197,577	$25,043,379
36					Mar-2042	4.461%		$1,197,309	$26,240,688
37					Mar-2043	2.231%		$598,789	$26,839,477
38						100.000%		$26,839,477	
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 2023 Electric ISR Revenue Requirement 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)
1	Book Depreciation - Excl. Intangibles	Col (a): Page 5 of 33, Line 19, column (d); Col (b): Page 5 of 33, Line 19, columns (e) and (f); Col (c): Page 5 of 33, Line 19, column (g)	$1,339,762	$1,339,762
2	Book Depreciation - Intangibles	Col (a): Page 8 of 33, Line 21 - Line 20, Column (l); Col (b): Page 8 of 33, Line 21 - Line 20, Sum of Columns (o) and (r); Col (c): Page 8 of 33, Line 21 - Line 20, Column (u)	$494,375	$494,375
3	Bonus Depreciation		$0	$0
4	Remaining MACRS Tax Depreciation - Excl. Intangibles	Col (a): - Page 6 of 33, Line 9, column, (e) Col (b): - Page 6 of 33, Sum of Lines 10 and 17, column, (e) Col (c): - Page 6 of 33, Line 18, column, (e)	($1,519,816)	($1,214,440)
5	Remaining MACRS Tax Depreciation - Intangibles	Col (a): - (Page 8 of 33, Line 18 - Line 17, Column (l)); Col (b): - (Page 8 of 33, Line 18 - Line 17, Sum of Columns (o) and (r)); Col (c): - (Page 8 of 33, Line 18 - Line 17, Column (u))	($256,432)	($513,297)
6	FY 2019 tax (gain)/loss on retirements		$0	$0
7	Cumulative Book / Tax Timer	Sum of Lines 1 through 6	$57,889	$106,400
8	Effective Tax Rate		21.00%	21.00%
9	Deferred Tax Reserve	Line 7 * Line 8	$12,157	$22,344
	Deferred Tax Not Subject to Proration			
10	Capital Repairs Deduction			
11	Cost of Removal			
12	Book/Tax Depreciation Timing Difference at 3/31/2018			
13	Cumulative Book / Tax Timer	Line 10 + Line 11 + Line 12	$0	$0
14	Effective Tax Rate		21%	21%
15	Deferred Tax Reserve	Line 13 × Line 14	$0	$0
16	Total Deferred Tax Reserve	Line 9 + Line 15	$12,157	$22,344
17	Net Operating Loss		$0	$0
18	Net Deferred Tax Reserve	Line 16 + Line 17	$12,157	$22,344
	Allocation of FY 2019 Estimated Federal NOL			
19	Cumulative Book/Tax Timer Subject to Proration	Line 7	$57,889	$106,400
20	Cumulative Book/Tax Timer Not Subject to Proration	Line 13	$0	$0
21	Total Cumulative Book/Tax Timer	Line 19 + Line 20	$57,889	$106,400
22	Total FY 2019 Federal NOL		$0	$0
23	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 20 ÷ Line 21) × Line 22	$0	$0
24	Allocated FY 2019 Federal NOL Subject to Proration	(Line 19 ÷ Line 21) × Line 22	$0	$0
25	Effective Tax Rate		21%	21%
26	Deferred Tax Benefit subject to proration	Line 24 × Line 25	$0	$0
27	Net Deferred Tax Reserve subject to proration	Line 9 + Line 26	$12,157	$22,344

		(d)	(e)	(f)	(g)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23
28	April	30	91.78%	$930	$1,709
29	May	31	83.29%	$844	$1,551
30	June	30	75.07%	$760	$1,398
31	July	31	66.58%	$674	$1,240
32	August	31	58.08%	$588	$1,081
33	September	30	49.86%	$505	$928
34	October	31	41.37%	$419	$770
35	November	30	33.15%	$336	$617
36	December	31	24.66%	$250	$459
37	January	31	16.16%	$164	$301
38	February	28	8.49%	$86	$158
39	March	31	0.00%	$0	$0
40	Total	365		$5,557	$10,213
41	Deferred Tax Without Proration	Line 27		$12,157	$22,344
42	Average Deferred Tax without Proration	Line 39 * 50%		$6,078	$11,172
43	Proration Adjustment	Line 40 - Line 42		($522)	($959)

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Fiscal Year 2023 Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	FY19 Total (c) = (a) + (b)	FY 20 Total (f) = (d) + (e)	FY 21 Total (i) = (g) + (h)	FY 22 Total (l) = (j) + (k)	FY Mar-2023 (Apr-May 2022) (o) = (m) + (n)	FY Mar-2023 (Jun 2022 -Mar 2023) (r) = (p) + (q)
	Capital Investment						NG	PPL
1	Start of Rev. Req. Period		09/01/18	04/01/19	04/01/20	04/01/21	04/01/22	05/25/22
2	End of Rev. Req. Period		03/31/19	03/31/20	03/31/21	03/31/22	05/24/22	03/31/23
3	Investment Name	Per Company's Book						
4	Work Order	Per Company's Book						
5	Total Spend		$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626
6	In ServiceDate	Per Company's Book						
7	Book AmortizationPeriod	Per Company's Book						
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$3,378,230	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,540,045
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
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
	Deferred Tax Calculation:							
11	Total Spend							
12	In Service Date							
13	Tax Amortizaton Period	Page 9 of 33						
14	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0	$0
15	Tax Bonus Rate	Per Tax Department						
16	Bonus Depreciation	Year 1 = (L. 5 - L. 14) × L.15, Then = 0	$0	$0	$0	$0	$0	$0
17	Beginning Acc. Tax Balance	(L. 5 - L. 14- L.16)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$1,153,427	$1,153,427	$2,691,675	$3,204,194	$3,460,626	$0
18	Ending Acc. Tax Balance	(L. 5 - L. 14- L.16) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$1,153,427	$2,691,675	$3,204,194	$3,460,626	$3,460,626	$513,297
19	Average Acc. Tax Balance	(Line 17 + Line 18) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410	$3,460,626	$256,649
20	Beginning Acc. Dep. Balance	Line 5 - Line 8	$82,396	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581
21	Ending Acc. Dep. Balance	Line 5 - Line 9	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581	$2,348,282
22	Average Acc. Dep. Balance	(Line 20 + Line 21) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719	$1,887,244	$2,134,432
23	Number of days							
24	Proration Percentage							
25	Average Book / Tax Timer	Line 19 - Line 22	$926,838	$1,304,582	$1,835,590	$1,725,691	$232,774	($1,599,974)
26	Effective Tax Rate							
27	Deferred Tax Reserve	Line 25 × Line 26	$194,636	$273,962	$385,474	$362,395	$48,883	($335,995)
	Rate Base Calculation:							
28	Average Book Balance	Line 10	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$232,774	$1,129,991
29	Deferred Tax Reserve	Line 27	$194,636	$273,962	$385,474	$362,395	$48,883	($335,995)
30	Average Rate Base	Line 28 - Line 29	$3,039,402	$2,568,695	$1,962,808	$1,491,512	$183,892	$1,465,985
	Revenue Requirement Calculation:							
31	Pre-Tax ROR	year 1 = Page 31 of 33, Line 27, column (e)×7÷12 Then = Page 31 of 33, Line 27(e)						
32	Return and Taxes	Line 30 × Line 31	$145,917	$211,404	$161,539	$122,751	$15,134	$120,651
33	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375	$66,674	$427,701
34	Annual Revenue Requirement	Line 32 + Line 33	$434,302	$705,779	$655,914	$617,127	$81,808	$548,352

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
MACRS Tables For Information Systems

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Fiscal Year 2023 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)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*			$27,837,942				
	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 23 of 33, Line 4(c)		$67,435,277	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$67,435,277	$0	$0	$0	$0
5	Retirements	Page 23 of 33 , Line 10 ,Col (c)		$4,015,632	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$63,419,645	$63,419,645	$63,419,645	$63,419,645	$63,419,645
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$67,435,277	$0	$0	$0	$0
8	Depreciation Expense	Page 27 of 33, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$38,322,907	$38,322,907	$38,322,907	$38,322,907	$38,322,907
10	Cost of Removal	Page 23 of 33 , Line 7 ,Col (c)		$11,332,719				
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$49,655,625**	**$49,655,625**	**$49,655,625**	**$49,655,625**	**$49,655,625**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	Page 25 of 33, 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 11 of 33, Line 28, Then = Page 11 of 33, Column (e)		$23,504,007	$4,305,759	$3,982,484	$545,069	$2,329,824
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$23,504,007	$27,809,766	$31,792,250	$32,337,319	
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/					$2,329,824
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$1,002,030	$2,004,061	$2,004,061	$296,491	$1,707,570
20	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$1,002,030	$3,006,091	$5,010,152	$5,306,643	$7,014,213
21	Cumulative Book / Tax Timer	Columns (c) & (d): Line 17 - Line 20, Then Line 18 - Line 20		$22,501,976	$24,803,674	$26,782,098	$27,030,675	($4,684,389)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (d)	3/					$5,306,643
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22						$622,254
24	Effective Tax Rate			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		$4,725,415	$5,208,772	$5,624,241	$5,676,442	$130,673
26	Add: FY 2020 Federal NOL Utilization	Page 23 of 33, Line 15, Col (c)	3/	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	$0
27	Net Deferred Tax Reserve before Proration Adjustmer	Sum of Lines 25 through 26		$3,262,435	$3,745,791	$4,161,260	$4,213,461	$130,673
	Rate Base Calculation:							
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$49,655,625	$49,655,625	$49,655,625	$49,655,625	$49,655,625
29	Accumulated Depreciation	-Line 20		($1,002,030)	($3,006,091)	($5,010,152)	($5,306,643)	($7,014,213)
30	Deferred Tax Reserve	-Line 27		($3,262,435)	($3,745,791)	($4,161,260)	($4,213,461)	($130,673)
31	Year End Rate Base before Deferred Tax Proratioı	Sum of Lines 28 through 30		$45,391,160	$42,903,743	$40,484,213	$40,135,521	$42,510,739
	Revenue Requirement Calculation:							
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 * Page 16 of 33, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2	4/	$16,573,333	$44,147,452	$41,693,978	$41,497,476	$41,497,476
33	Proration Adjustment	Page 12 of 33, Line 41		$30,912	$18,700	$17,833	$7,849	$7,849
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$16,604,245	$44,166,151	$41,711,811	$41,505,326	$41,505,326
35	Pre-Tax ROR	Page 31 of 33, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14	2/				14.79%	85.21%
37	Return and Taxes	Cols (a) through (c) and (f): L 34 * L 35; Cols (d) and (e): L 34 * L 35 * L 36	2/	$1,366,529	$3,634,874	$3,432,882	$505,364	$2,910,524
38	Book Depreciation	Line 19		$1,002,030	$2,004,061	$2,004,061	$296,491	$1,707,570
39	**Annual Revenue Requirement**	Line 37 + Line 38		**$2,368,560**	**$5,638,935**	**$5,436,943**	**$801,855**	**$4,618,094**
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 25 of 33, 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 2023 Electric ISR Revenue Requirement 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 33, Line 3		$67,435,277	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%					
3	Capital Repairs Deduction	Line 1 * Line 2		$5,738,742	NG MACRS basis:	Line 22, Column (a)		$59,644,817	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Proration	MACRS	Tax Depr
6	Plant Additions	Line 1		$67,435,277	FY Mar-2020	3.750%		$2,236,681	$23,504,007
7	Plant Additions			$0	FY Mar-2021	7.219%		$4,305,759	$27,809,766
8	Less Capital Repairs Deduction	Line 3		$5,738,742	FY Mar-2022	6.677%		$3,982,484	$31,792,250
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$61,696,535	FY Mar-2023 (Apr-May 2022)	6.177%	0.914%	$545,069	$32,337,319
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%					
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$61,696,535	PPL Acquisition - May 25, 2022				
12	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%	Book Cost	Line 1, Column (a)		$67,435,277	
13	Bonus Depreciation Rate	1 * 0% * 25%		0.00%	Cumulative Book Depreciation	- Page 10 of 33, Line 20, Col (d)		($5,306,643)	
14	Total Bonus Depreciation Rate	Line 12 + Line 13		3.33%	PPL MACRS basis:	Line 12(e) + Line 13(e)		$62,128,634	
15	Bonus Depreciation	Line 11 * Line 14		$2,051,718					
16					FY Mar-2023 (Jun-Mar 2023)	3.750%		$2,329,824	$2,329,824
17	Remaining Tax Depreciation				Mar-2024	7.219%		$4,485,066	$6,814,890
18	Plant Additions	Line 1		$67,435,277	Mar-2025	6.677%		$4,148,329	$10,963,219
19	Less Capital Repairs Deduction	Line 3		$5,738,742	Mar-2026	6.177%		$3,837,686	$14,800,904
20	Less Bonus Depreciation	Line 15		$2,051,718	Mar-2027	5.713%		$3,549,409	$18,350,313
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$59,644,817	Mar-2028	5.285%		$3,283,498	$21,633,812
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2029	4.888%		$3,036,848	$24,670,659
23	Remaining Tax Depreciation	Line 21 * Line 22		$2,236,681	Mar-2030	4.522%		$2,809,457	$27,480,116
24					Mar-2031	4.462%		$2,772,180	$30,252,296
25	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147	Mar-2032	4.461%		$2,771,558	$33,023,854
26	Cost of Removal	Page 10 of 33, Line 10		$11,332,719	Mar-2033	4.462%		$2,772,180	$35,796,034
27					Mar-2034	4.461%		$2,771,558	$38,567,592
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$23,504,007	Mar-2035	4.462%		$2,772,180	$41,339,772
29					Mar-2036	4.461%		$2,771,558	$44,111,330
30					Mar-2037	4.462%		$2,772,180	$46,883,510
31					Mar-2038	4.461%		$2,771,558	$49,655,068
32					Mar-2039	4.462%		$2,772,180	$52,427,248
33					Mar-2040	4.461%		$2,771,558	$55,198,806
34					Mar-2041	4.462%		$2,772,180	$57,970,986
35					Mar-2042	4.461%		$2,771,558	$60,742,544
36					Mar-2043	2.231%		$1,386,090	$62,128,634
37						100.000%		$62,128,634	
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 2023 Electric ISR Revenue Requirement 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)
1	Book Depreciation	Col (a): Page 10 of 33, Line 19, column (c); Col (b): Page 10 of 33, Line 19, columns (d) and (e); Col (c): Page 10 of 33, Line 19, column (f)		$2,004,061	$2,004,061
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 11 of 33, Line 8, column, (e); Col (b): - Page 11 of 33, Sum of Lines 9 and 16, column, (e); Col (c): - Page 11 of 33, Line 17, column, (e)		($3,982,484)	($2,874,892)
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		($1,978,424)	($870,832)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($415,469)	($182,875)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
9	Cost of Removal	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0			
10	Book/Tax Depreciation Timing Difference at 3/31/2020				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		$0	$0
12	Effective Tax Rate			21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12		$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13		($415,469)	($182,875)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($415,469)	($182,875)
	Allocation of FY 2020 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5		($1,978,424)	($870,832)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($1,978,424)	($870,832)
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		$0	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		$0	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		$0	$0
23	Effective Tax Rate			21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($415,469)	($182,875)
		(d)	(e)	(f)	(g)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23
26	April	30	91.78%	($31,777)	($13,987)
27	May	31	83.29%	($28,836)	($12,693)
28	June	30	75.07%	($25,991)	($11,440)
29	July	31	66.58%	($23,050)	($10,146)
30	August	31	58.08%	($20,109)	($8,851)
31	September	30	49.86%	($17,264)	($7,599)
32	October	31	41.37%	($14,323)	($6,305)
33	November	30	33.15%	($11,478)	($5,052)
34	December	31	24.66%	($8,537)	($3,758)
35	January	31	16.16%	($5,596)	($2,463)
36	February	28	8.49%	($2,941)	($1,294)
37	March	31	0.00%	$0	$0
38	Total	365		($189,902)	($83,588)
39	Deferred Tax Without Proration	Line 25		($415,469)	($182,875)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 16 of 33, Line 16, Col (e); then = Line 39 * 50%		($207,734)	($91,437)
41	Proration Adjustment	Line 38 - Line 40		$17,833	$7,849

Column Notes:

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

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Fiscal Year 2023 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)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*			$35,318,912			
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 23 of 33, Line 4(d)		$115,360,166	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$115,360,166	$0	$0	$0
5	Retirements	Page 23 of 33 , Line 10 ,Col (d)		$21,996,026	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$93,364,140	$93,364,140	$93,364,140	$93,364,140
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$115,360,166	$0	$0	$0
8	Depreciation Expense	Page 27 of 33, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$65,453,245	$65,453,245	$65,453,245	$65,453,245
10	Cost of Removal	Page 23 of 33 , Line 7 ,Col (d)		$10,232,810			
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$75,686,055**	**$75,686,055**	**$75,686,055**	**$75,686,055**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	Page 25 of 33, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%
13	Number of days		2/			54	311
14	Proration Percentage		2/			14.79%	85.21%
15	Vintage Year Tax Depreciation:						
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 14 of 33, Line 28, Column (a), Then = Line Page 14 of 33 , Column (e)		$44,175,121	$6,372,048	$871,935	$4,143,683
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$44,175,121	$50,547,169	$51,419,105	
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/				$4,143,683
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,475,153	$2,950,307	$436,484	$2,513,823
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$1,475,153	$4,425,460	$4,861,944	$7,375,767
21	Cumulative Book / Tax Timer	Columns (a) through (c): Line 17 - Line 20, Then Line 18 - Line 20		$42,699,968	$46,121,709	$46,557,161	($3,232,084)
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (c)	3/				$4,861,944
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$1,629,860
24	Effective Tax Rate			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		$8,966,993	$9,685,559	$9,777,004	$342,271
26	Add: FY 2021 Federal (NOL) Utilization	Page 23 of 33, Line 15, Col (d)	3/	($5,639,147)	($5,639,147)	($5,639,147)	$0
27	Net Deferred Tax Reserve beforee Proration Adjustmer	Sum of Lines 25 through 26		$3,327,846	$4,046,411	$4,137,856	$342,271
	Rate Base Calculation:						
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$75,686,055	$75,686,055	$75,686,055	$75,686,055
29	Accumulated Depreciation	-Line 20		($1,475,153)	($4,425,460)	($4,861,944)	($7,375,767)
30	Deferred Tax Reserve	-Line 27		($3,327,846)	($4,046,411)	($4,137,856)	($342,271)
31	Year End Rate Base before Deferred Tax Proratioı	Sum of Lines 28 through 30		$70,883,056	$67,214,184	$66,686,255	$67,968,018
	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/	$35,441,528	$69,048,620	$67,591,101	$67,591,101
33	Proration Adjustment	Page 15 of 33, Line 41		$16,539	$30,843	$18,616	$18,616
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$35,458,067	$69,079,462	$67,609,717	$67,609,717
35	Pre-Tax ROR	Page 31 of 33, Line 35		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/	$2,918,199	$5,685,240	$823,209	$4,741,071
38	Book Depreciation	Line 19		$1,475,153	$2,950,307	$436,484	$2,513,823
39	Revenue Requirement of Intangible Assets						
40	**Annual Revenue Requirement**	**Line 37 + Line 38 + Line 39**		**$4,393,352**	**$8,635,547**	**$1,259,692**	**$7,254,894**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 25 of 33, Line 3, Col (e))

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

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

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement 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 33, Line 3(a)		$115,360,166	20 Year MACRS Depreciation				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%					
3	Capital Repairs Deduction	Line 1 * Line 2		$27,092,422	MACRS basis:	Line 21, Column (a)		$88,267,744	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$115,360,166	FY Mar-2021	3.750%		$3,310,040	$44,175,121
7	Plant Additions			$0	FY Mar-2022	7.219%		$6,372,048	$50,547,169
8	Less Capital Repairs Deduction	Line 3		$27,092,422	FY Mar-2023 (Apr-May 2022)	6.677%	0.988%	$871,935	$51,419,105
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$88,267,744					
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	PPL Acquisition - May 25, 2022				
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Book Cost	Line 1, Column (a)		$115,360,166	
12	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%	Cumulative Book Depreciation	- Page 13 of 33, Line 20, Col (c)		($4,861,944)	
13	Bonus Depreciation Rate	1 * 25% * 0%		0.00%	PPL MACRS basis:	Line 11(e) + Line 12(e)		$110,498,222	
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%		$4,143,683	$4,143,683
16					Mar-2024	7.219%		$7,976,867	$12,120,550
17	Remaining Tax Depreciation				Mar-2025	6.677%		$7,377,966	$19,498,516
18	Plant Additions	Line 1		$115,360,166	Mar-2026	6.177%		$6,825,475	$26,323,991
19	Less Capital Repairs Deduction	Line 3		$27,092,422	Mar-2027	5.713%		$6,312,763	$32,636,755
20	Less Bonus Depreciation	Line 15		$0	Mar-2028	5.285%		$5,839,831	$38,476,586
21	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 18 - Line 19 - Line 20		$88,267,744	Mar-2029	4.888%		$5,401,153	$43,877,739
22	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2030	4.522%		$4,996,730	$48,874,469
23	Remaining Tax Depreciation	Line 21 * Line 22		$3,310,040	Mar-2031	4.462%		$4,930,431	$53,804,899
24					Mar-2032	4.461%		$4,929,326	$58,734,225
25	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$3,539,849	Mar-2033	4.462%		$4,930,431	$63,664,656
26	Cost of Removal	Page 13 of 33, Line 10		$10,232,810	Mar-2034	4.461%		$4,929,326	$68,593,981
27					Mar-2035	4.462%		$4,930,431	$73,524,412
28	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 15, 23, 25, and 26		$44,175,121	Mar-2036	4.461%		$4,929,326	$78,453,738
29					Mar-2037	4.462%		$4,930,431	$83,384,168
30					Mar-2038	4.461%		$4,929,326	$88,313,494
31					Mar-2039	4.462%		$4,930,431	$93,243,925
32					Mar-2040	4.461%		$4,929,326	$98,173,250
33					Mar-2041	4.462%		$4,930,431	$103,103,681
34					Mar-2042	4.461%		$4,929,326	$108,033,007
35					Mar-2043	2.231%		$2,465,215	$110,498,222
36						100.00%		$110,498,222	
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 2023 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23-NG (b)
1	Book Depreciation	Col (a): Page 13 of 33, Line 19, column (b); Col (b): Page 13 of 33, Line 19, columns (c) and (d); Col (c): Page 13 of 33, Line 19, column (e)	$2,950,307	$2,950,307
2	Bonus Depreciation	Page 14 of 33, Line 20	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 14 of 33, Line 7, column, (e); Col (b): - Page 14 of 33, Sum of Lines 8 and 15, column (e); Col (c): - Page 14 of 33, Line 16, column, (e)	($6,372,048)	($5,015,619)
4	FY 2021 tax (gain)/loss on retirements	- Page 14 of 33, Line 25		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,421,742)	($2,065,312)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($718,566)	($433,715)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 14 of 33, Line 3		
9	Cost of Removal	- Page 14 of 33, Line 26		
10	Book/Tax Depreciation Timing Difference at 3/31/2021			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12		$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($718,566)	($433,715)
15	Net Operating Loss	Page 13 of 33, Line 26	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($718,566)	($433,715)
	Allocation of FY 2021 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($3,421,742)	($2,065,312)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($3,421,742)	($2,065,312)
20	Total FY 2021 Federal NOL (Utilization)	- Page 13 of 33, Line 26 / 21%	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($718,566)	($433,715)

		(d)	(e)	(f)	(g)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23-NG
26	April	30	91.78%	($54,959)	($33,172)
27	May	31	83.29%	($49,873)	($30,103)
28	June	30	75.07%	($44,951)	($27,132)
29	July	31	66.58%	($39,866)	($24,062)
30	August	31	58.08%	($34,780)	($20,993)
31	September	30	49.86%	($29,858)	($18,022)
32	October	31	41.37%	($24,772)	($14,952)
33	November	30	33.15%	($19,851)	($11,982)
34	December	31	24.66%	($14,765)	($8,912)
35	January	31	16.16%	($9,679)	($5,842)
36	February	28	8.49%	($5,086)	($3,070)
37	March	31	0.00%	$0	$0
38	Total	365		($328,440)	($198,242)
39	Deferred Tax Without Proration	Line 25		($718,566)	($433,715)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($359,283)	($216,858)
41	Proration Adjustment	Line 38 - Line 40		$30,843	$18,616

Column Notes:

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

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement 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	8,218,322	6,236,917	1,981,405	0.958	1,898,846	2.94%
3	2	May-20	8,218,322	6,236,917	1,981,405	0.875	1,733,729	2.94%
4	3	Jun-20	8,218,322	6,236,917	1,981,405	0.792	1,568,612	2.94%
5	4	Jul-20	8,218,322	6,236,917	1,981,405	0.708	1,403,495	2.94%
6	5	Aug-20	8,218,322	6,236,917	1,981,405	0.625	1,238,378	2.94%
7	6	Sep-20	8,218,322	-	8,218,322	0.542	4,451,591	12.19%
8	7	Oct-20	8,218,322	-	8,218,322	0.458	3,766,731	12.19%
9	8	Nov-20	8,218,322	-	8,218,322	0.375	3,081,871	12.19%
10	9	Dec-20	8,218,322	-	8,218,322	0.292	2,397,010	12.19%
11	10	Jan-21	8,218,322	-	8,218,322	0.208	1,712,150	12.19%
12	11	Feb-21	8,218,322	-	8,218,322	0.125	1,027,290	12.19%
13	12	Mar-21	8,218,322	-	8,218,322	0.042	342,430	12.19%
14		Total	$98,619,860	$31,184,583	$67,435,277		$24,622,135	100.00%
15	**Total September 2020 through March 2021**			**$**	**57,528,252**			
16	**FY 2020 Weighted Average Incremental Rate Base Percentage**						**36.51%**	

Column (a)=Page 23 of 33, Line 1(c)
Column(b)=Page 23 of 33, Line 3(c)
Line 15 = sum of Line 7(c) through Line 13(c)
Line 16 = Line 14(f)/Line 14(c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2023 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)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*	Docket 5098, P 29 of 29. Line 1(a)		$44,263,589		
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Docket 5098, P 29 of 29. Line 2(a)		$42,200,430		
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 23 of 33, Line 4(e)		$86,464,019	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$86,464,019	$0	$0
5	Retirements	Page 23 of 33 , Line 10 ,Col (e)		$34,853,004	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$51,611,015	$51,611,015	$51,611,015
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$86,464,019	$0	$0
8	Depreciation Expense	Page 27 of 33, Line 62, Col (d)		$49,906,920	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$36,557,099	$36,557,099	$36,557,099
10	Cost of Removal	Page 23 of 33 , Line 7 ,Col (e)		$7,600,505	$0	$0
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$44,157,603**	**$44,157,603**	**$44,157,603**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	Page 25 of 33, Line 3, Col (e)	1/	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 33, Line 27, Column (a), Then = Line Page 18 of 33 , Column (e)		$41,638,714	$649,462	$3,202,773
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	3/	$41,638,714	$42,288,176	
18	Cumulative Tax Depreciation-PPL	Year 1 = Line 16; then = Prior Year Line 18 + Current Year Line 16	3/			$3,202,773
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	2/	$815,454	$241,285	$1,389,623
20	Cumulative Book Depreciation	Prior Year Line 20 + Current Year Line 19		$815,454	$1,056,739	$2,446,362
21	Cumulative Book / Tax Timer	Columns (a) & (b): Line 17 - Line 20, Then Line 18 - Line 20		$40,823,260	$41,231,437	$756,411
22	Less: Cumulative Book Depreciation at Acquisition	Line 20 Column (b)	3/			$1,056,739
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22				$1,813,150
24	Effective Tax Rate			21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Cols (a) and (b): Line 21 * Line 24, Then Line 23 * Line 24		$8,572,885	$8,658,602	$380,761
26	Add: FY 2022 Federal (NOL) Utilization	Page 23 of 33, Line 15, Col (e)	3/	($3,602,966)	($3,602,966)	$0
27	Net Deferred Tax Reserve before Proration Adjustmei	Sum of Lines 25 through 26		$4,969,918	$5,055,636	$380,761
	Rate Base Calculation:					
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$44,157,603	$44,157,603	$44,157,603
29	Accumulated Depreciation	-Line 20		($815,454)	($1,056,739)	($2,446,362)
30	Deferred Tax Reserve	-Line 27		($4,969,918)	($5,055,636)	($380,761)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$38,372,231	$38,045,228	$41,330,480
	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/	$19,186,115	$39,851,355	$39,851,355
33	Proration Adjustment	Page 19 of 33, Line 41		$13,204	$20,022	$20,022
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$19,199,320	$39,871,378	$39,871,378
35	Pre-Tax ROR	Page 31 of 33, Line 35		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/	$1,580,104	$485,470	$2,795,945
38	Book Depreciation	Line 19		$815,454	$241,285	$1,389,623
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$2,395,558**	**$726,755**	**$4,185,568**
40	FY 2022 Revenue Requirement before tax adjustments			$2,364,086		
41	2022 Tax True-Up			$31,472		

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 25 of 33, Line 3, Col (e))

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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 2023 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2022 Incremental Capital Investments

Line No.				Fiscal Year 2022 (a)	(b)	(c)	(d)	(e)	(f)
	Capital Repairs Deduction					20 Year MACRS Depreciation			
1	Plant Additions	Page 17 of 33, Line 3		$86,464,019					
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.67%					
3	Capital Repairs Deduction	Line 1 * Line 2		$25,653,874	NG MACRS basis:	Line 22, Column (a)		$60,810,145	
4								Annual	Cumulative
5	Bonus Depreciation				Fiscal Year		Prorated	MACRS	Tax Depr
6	Plant Additions	Line 1		$86,464,019	FY Mar-2022	3.750%		$2,280,380	$41,638,714
7	Plant Additions			$0	FY Mar-2023 (Apr-May 2022)	7.219%	1.068%	$649,462	$42,288,176
8	Less Capital Repairs Deduction	Line 3		$25,653,874					
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$60,810,145	PPL Acquisition - May 25, 2022				
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	Book Cost	Line 1, Column (a)		$86,464,019	
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	Cumulative Book Depreciation	- Page 17 of 33, Line 20, Col (b)		($1,056,739)	
12	Bonus Depreciation Rate	at 0%		0.00%	PPL MACRS basis:	Line 10(e) + Line 11(e)		$85,407,280	
13	Total Bonus Depreciation Rate	Line 12		0.00%					
14	Bonus Depreciation	Line 11 * Line 13		$0	FY Mar-2023 (Jun-Mar 2023)	3.750%		$3,202,773	$3,202,773
15					Mar-2024	7.219%		$6,165,552	$9,368,325
16	Remaining Tax Depreciation				Mar-2025	6.677%		$5,702,644	$15,070,969
17	Plant Additions	Line 1		$86,464,019	Mar-2026	6.177%		$5,275,608	$20,346,576
18	Less Capital Repairs Deduction	Line 3		$25,653,874	Mar-2027	5.713%		$4,879,318	$25,225,894
19	Less Bonus Depreciation	Line 14		$0	Mar-2028	5.285%		$4,513,775	$29,739,669
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$60,810,145	Mar-2029	4.888%		$4,174,708	$33,914,377
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	Mar-2030	4.522%		$3,862,117	$37,776,494
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,280,380	Mar-2031	4.462%		$3,810,873	$41,587,367
23					Mar-2032	4.461%		$3,810,019	$45,397,386
24	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$6,103,955	Mar-2033	4.462%		$3,810,873	$49,208,258
25	Cost of Removal	Page 17 of 33, Line 10		$7,600,505	Mar-2034	4.461%		$3,810,019	$53,018,277
26					Mar-2035	4.462%		$3,810,873	$56,829,150
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$41,638,714	Mar-2036	4.461%		$3,810,019	$60,639,169
28					Mar-2037	4.462%		$3,810,873	$64,450,042
29					Mar-2038	4.461%		$3,810,019	$68,260,060
30					Mar-2039	4.462%		$3,810,873	$72,070,933
31					Mar-2040	4.461%		$3,810,019	$75,880,952
32					Mar-2041	4.462%		$3,810,873	$79,691,825
33					Mar-2042	4.461%		$3,810,019	$83,501,844
34					Mar-2043	2.231%		$1,905,436	$85,407,280
35						100.000%		$85,407,280	
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 2023 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		FY22 (a)	FY23-NG (b)
1	Book Depreciation	Col (a): Page 17 of 33, Line 19, column (a); Col (b): Page 17 of 33, Line 19, columns (b) and (c); Col (c): Page 17 of 33, Line 19, column (d)	$815,454	$1,630,908
2	Bonus Depreciation	Page 14 of 33, Line 20	$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): - Page 18 of 33, Line 6, column, (e); Col (b): - Page 18 of 33, Sum of Lines 7 and 14, column (e); Col (c): - Page 18 of 33, Line 15, column, (e)	($2,280,380)	($3,852,235)
4	FY 2022 tax (gain)/loss on retirements	- Page 18 of 33, Line 24		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,464,926)	($2,221,327)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($307,635)	($466,479)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 18 of 33, Line 3		
9	Cost of Removal	- Page 18 of 33, Line 25		
10	Book/Tax Depreciation Timing Difference at 3/31/2022			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($307,635)	($466,479)
15	Net Operating Loss	Page 17 of 33, Line 26	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($307,635)	($466,479)
	Allocation of FY 2022 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,464,926)	($2,221,327)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($1,464,926)	($2,221,327)
20	Total FY 2022 Federal NOL (Utilization)	- Page 17 of 33, Line 26 / 21%	$0	$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($307,635)	($466,479)

		(d)	(e)	(f)	(g)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22	FY23-NG
26	April	30	91.78%	($23,529)	($35,678)
27	May	31	83.29%	($21,352)	($32,377)
28	June	30	75.07%	($19,245)	($29,182)
29	July	31	66.58%	($17,067)	($25,880)
30	August	31	58.08%	($14,890)	($22,578)
31	September	30	49.86%	($12,783)	($19,383)
32	October	31	41.37%	($10,606)	($16,082)
33	November	30	33.15%	($8,499)	($12,887)
34	December	31	24.66%	($6,321)	($9,585)
35	January	31	16.16%	($4,144)	($6,284)
36	February	28	8.49%	($2,177)	($3,302)
37	March	31	0.00%	$0	$0
38	Total	365		($140,613)	($213,217)
39	Deferred Tax Without Proration	Line 25		($307,635)	($466,479)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($153,817)	($233,239)
41	Proration Adjustment	Line 38 - Line 40		$13,204	$20,022

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2023 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)
	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/	$7,888,460	$45,431,685
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$14,018,685	$80,737,243
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$14,018,685	$80,737,243
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		$11,385,532	$65,572,231
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$14,018,685	$80,737,243
8	Depreciation Expense	Page 27 of 33, Line 62, Col (d)	2/	$7,383,490	$42,523,431
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$6,635,196	$38,213,812
10	Cost of Removal	Company's Record	2/	$1,149,913	$6,622,647
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$7,785,109**	**$44,836,459**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 25 of 33, 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	Col (a) = Page 21 of 33, Column (a), Line 27; Col (b) = Page 21 of 33, Col (b), Lines 18,24,25 + Col (e), Line 15, Then remaining years from Page 21 of 33, Col (e)		$6,582,033	$38,426,590
16	Cumulative Tax Depreciation-NG	Col (a) = Line 15; then 0	3/	$6,582,033	
17	Cumulative Tax Depreciation-PPL	Col (b) = Line 15; then = Prior Year Line 17 + Current Year Line 15	3/		$38,426,590
18	Book Depreciation	Year 1 (Columns (a) and (b)) = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$179,891	$1,036,041
19	Cumulative Book Depreciation	Year 1 = Line 18; then = Prior Year Line 19 + Current Year Line 18		$179,891	$1,215,933
20	Book / Tax Timer	Line 15 - Line 18		$6,402,141	$37,390,549
21	Cumulative Book / Tax Timer -NG	Col (a) = Line 20, Column (a), Then = 0	3/	$6,402,141	
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/		$37,390,549
23	Cumulative Book / Tax Timer - Total	Line 21 + Line 22		$6,402,141	$37,390,549
24	Effective Tax Rate			21.00%	21.00%
25	Deferred Tax Reserve	Line 23 × Line 24		$1,344,450	$7,852,015
26	Add: FY 2023 Federal (NOL) Utilization	Page 23 of 33 , Line 13 ,Col (f)	3/	$937,665	
27	Net Deferred Tax Reserve before Proration Adjustmer	Sum of Lines 25 through 26		$2,282,115	$7,852,015
	Rate Base Calculation:				
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$7,785,109	$44,836,459
29	Accumulated Depreciation	Year 1 (Cols (a) and (b)) = -Line 18; Then = -Line 19		($179,891)	($1,036,041)
30	Deferred Tax Reserve	-Line 27		($2,282,115)	($7,852,015)
31	Year End Rate Base before Deferred Tax Proratioı	Sum of Lines 28 through 30		$5,323,103	$35,948,402
	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/	$2,661,551	$17,974,201
33	Proration Adjustment	Page 22 of 33, Line 41	2/	$63,752	$18,193
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$2,725,303	$17,992,394
35	Pre-Tax ROR	Page 31 of 33, Line 35		8.23%	8.23%
36	Proration	Line 13			
37	Return and Taxes	Line 34 x Line 35		$224,292	$1,480,774
38	Book Depreciation	Line 18		$179,891	$1,036,041
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$404,184**	**$2,516,815**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 25 of 33, Line 3, Col (e))
2/ Columns (a) and (b) represent the 12 months within fiscal year 2023, but activity is separated to accommodate the impacts of the acquisition as described in note 3.
3/ National Grid and PPL Corporation ("PPL") elected to treat PPL's acquisition of The Narragansett Electric Company ("NECO") from National Grid on May 25, 2022 as an asset sale for U.S. federal income tax purposes under Internal Revenue Code Section 338(h)(10). As a result of this election, PPL was deemed to acquire the assets of NECO at fair market value (essentially equivalent to book value) for tax purposes. The resulting "step-up" in tax basis eliminates most book/tax timing differences and the related accumulated net deferred income tax liabilities as of the acquisition date, at which time PPL will reset the book/tax timing difference as if PPL purchased a new asset in the year of acquisition and will begin depreciating the new tax basis. Book cost, book accumulated depreciation and book depreciation continue as if the acqusition never took place.
4/ Column (c) takes the average of the "Year End Rate Base before Deferred Tax Proration" at the beginning of the fiscal year on Line 32, Columns (a) and (b) and the end of the fiscal year on Line 30, Column (c). See note 2.

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2023-NG Incremental Capital Investments

Line No.				Apr 1-May 24, 2022 2023-NG (a)	PPL May 25-Mar 31, 2023 FY 2023 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 20 of 33, Line 3, Columns (a) through (c)		$14,018,685	$80,737,243
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.67%	29.67%
3	Capital Repairs Deduction	Line 1 * Line 2		$4,159,344	$23,954,740
4					
5	Bonus Depreciation				
6	Plant Additions	Line 1		$14,018,685	$80,737,243
7	Plant Additions			$0	$0
8	Less Capital Repairs Deduction	Line 3		$4,159,344	$23,954,740
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$9,859,341	$56,782,503
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	$0
12	Bonus Depreciation Rate	at 0%		0.00%	0.00%
13	Total Bonus Depreciation Rate	Line 12		0.00%	0.00%
14	Bonus Depreciation	Line 11 * Line 13		$0	$0
15					
16	Remaining Tax Depreciation				
17	Plant Additions	Line 1		$14,018,685	$80,737,243
18	Less Capital Repairs Deduction	Line 3		$4,159,344	$23,954,740
19	Less Bonus Depreciation	Line 14		$0	$0
20	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$9,859,341	$56,782,503
21	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	3.750%
22	Remaining Tax Depreciation	Line 20 * Line 21		$369,725	$2,129,344
23					
24	FY23 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$903,051	$5,200,904
25	Cost of Removal	Page 20 of 33, Line 10		$1,149,913	$6,622,647
26					
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$6,582,033	$37,907,635
28					
29	Reconcilation of MACRS Tax Depreciation:				
30	Apr 1 -May 24, 2022 Plant Additions	Line 1, Column (a)			$14,018,685
31	Cumulative Book Depreciaiton through May 24, 2022	Page 20 of 33, Line 18, Col (a)			($179,891)
32	2022 Plant Additions (Net Book) through Acquisition	Line 30 + Line 31			$13,838,794
33	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%
34	Tax Depreciation	Line 32 * Line 33			$518,954
35					
36	MACRS Basis in May 25-Mar 2023 Plant Additions	Line 20, Column (b)			$56,782,503
37	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946			3.750%
38	Tax Depreciation	Line 36 * Line 37			$2,129,343
39					
40	Total MACRS Tax Depreciation	Sum of Lines 34, 38, Column (b)			$2,648,297
41					
42	1/ Per Tax Department				
43	2/ Per Tax Department				

20 Year MACRS Depreciation

(c)	(d)	(e)	(f)
MACRS basis:	Line 20, Column (a)	$9,859,341	
		Annual	Cumulative
Fiscal Year		MACRS	Tax Depr
FY Mar-2023 (Apr-May 2022)	3.750%	$369,725	$6,582,033
PPL Acquisition - May 25, 2022			
Book Cost	Line 1, Column (a)	$14,018,685	
Cumulative Book Depreciation	- Page 20 of 33, Line 18, Col (a)	($179,891)	
MACRS basis from Acquisition:	Line 9(e) + Line 10(e)	$13,838,794	
MACRS basis (Jun-Mar 2023)	Line 20, Column (b)	$56,782,503	
Total MACRS Basis in 2022	Line 11(e) + Line 12(e)	$70,621,297	
FY Mar-2023 (Jun-Mar 2023)	3.750%	$2,648,299	$38,426,590
Mar 2024	7.219%	$5,098,151	$43,524,741
Mar 2025	6.677%	$4,715,384	$48,240,125
Mar 2026	6.177%	$4,362,277	$52,602,403
Mar 2027	5.713%	$4,034,595	$56,636,997
Mar 2028	5.285%	$3,732,336	$60,369,333
Mar 2029	4.888%	$3,451,969	$63,821,302
Mar 2030	4.522%	$3,193,495	$67,014,797
Mar 2031	4.462%	$3,151,122	$70,165,919
Mar 2032	4.461%	$3,150,416	$73,316,335
Mar 2033	4.462%	$3,151,122	$76,467,457
Mar 2034	4.461%	$3,150,416	$79,617,873
Mar 2035	4.462%	$3,151,122	$82,768,996
Mar 2036	4.461%	$3,150,416	$85,919,412
Mar 2037	4.462%	$3,151,122	$89,070,534
Mar 2038	4.461%	$3,150,416	$92,220,950
Mar 2039	4.462%	$3,151,122	$95,372,072
Mar 2040	4.461%	$3,150,416	$98,522,488
Mar 2041	4.462%	$3,151,122	$101,673,611
Mar 2042	4.461%	$3,150,416	$104,824,027
Mar 2043	2.231%	$1,575,561	$106,399,588
	100.00%	$70,621,297	

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2023 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration		4/1/22 - 5/24/2022 FY Mar-2023 (a)	5/25/22 - 3/31/23 FY Mar-2023 (b)
1	Book Depreciation	Page 20 of 33, Line 18, Columns (a) through (e)	$179,891	$1,036,041
2	Bonus Depreciation	- Page 21 of 33, Line 14	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 21 of 33, column (e), Lines 6,18,19,20	($369,725)	($2,648,299)
4	FY 2023 tax (gain)/loss on retirements	- Page 21 of 33, Line 24	($903,051)	($5,200,904)
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,092,885)	($6,813,161)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($229,506)	($1,430,764)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 21 of 33, Line 3	($4,159,344)	($23,954,740)
9	Cost of Removal	- Page 21 of 33, Line 25	($1,149,913)	($6,622,647)
10	Book/Tax Depreciation Timing Difference at 3/31/2023			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($5,309,257)	($30,577,387)
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($1,114,944)	($6,421,251)
14	Total Deferred Tax Reserve	Line 7 + Line 13	($1,344,450)	($7,852,015)
15	Net Operating Loss	- Page 20 of 33, Line 26	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($1,344,450)	($7,852,015)
	Allocation of FY 2023 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,092,885)	($6,813,161)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($5,309,257)	($30,577,387)
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($6,402,142)	($37,390,549)
20	Total FY 2023 Federal NOL (Utilization)	- Page 20 of 33, Line 26 / 21%	$0	$0
21	Allocated FY 2023 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2023 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($229,506)	($1,430,764)

	Proration Calculation	(e) Number of Days in Month	(f) Proration Percentage	(g) FY Mar-2023	(h) FY Mar-2023
26	April	30	91.78%	($51,001)	
27	May	31	83.29%	$0	($127,142)
28	June	30	75.07%		($114,595)
29	July	31	66.58%		($101,630)
30	August	31	58.08%		($88,665)
31	September	30	49.86%		($76,118)
32	October	31	41.37%		($63,153)
33	November	30	33.15%		($50,606)
34	December	31	24.66%		($37,641)
35	January	31	16.16%		($24,676)
36	February	28	8.49%		($12,965)
37	March	31	0.00%		$0
38	Total	365		($51,001)	($697,189)
39	Deferred Tax Without Proration	Line 25		($229,506)	($1,430,764)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($114,753)	($715,382)
41	Proration Adjustment	Line 38 - Line 40		$63,752	$18,193

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
FY 2018 - 2023 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)	Fiscal Year 2023 (f)
	Capital Investment							
1	ISR - Eligible Capital Investment	Col (a) = FY 2018 ISR Docket No.4682, Att MAL-1 P2, L3; Col (b)=FY 2019 ISR Docket No.4783, Att PCE-1 P3, Table 1; Col (c)= Section I of Att. PCE-1, Table 2	$91,309,377	$110,051,680	$98,619,860	$115,360,166	$86,464,019	$94,755,928
2	Intangible Assest included in Total Allowed Discretionary Capital	Col (a) =0; Col (b) = FY 2019 ISR Docket No. 4783, Att. MAL-1,Page 30 of 38, Line13; Col (c) = Actual per Operation	$0	$3,460,626	$0	$0	$0	$0
3	ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k)	$74,843,000	$74,843,000	$31,184,583	$0	$0	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$16,466,377	$31,748,054	$67,435,277	$115,360,166	$86,464,019	$94,755,928
	Cost of Removal							
5	ISR - Eligible Cost of Removal	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)= Section 1 of Att. PCE-1, Table 3	$9,952,716	$8,209,732	$14,770,644	$10,438,210	$7,686,088	$7,772,560
6	ISR - Eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L10×3÷12, [P1]L26+L45×7÷12; Col(b)=[P1]L45×5÷12+[P2]L18×7÷12; Col (c) = [P2]L18×5÷12+L39×7÷12	$8,259,707	$7,848,009	$3,437,925	$205,400	$85,583	$0
7	Incremental Cost of Removal	Line 5 - Line 6	$1,693,009	$361,723	$11,332,719	$10,232,810	$7,600,505	$7,772,560
	Retirements							
8	ISR - Eligible Retirements/Actual	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)=Per Company's Book	$15,206,748	$12,015,754	$13,944,441	$22,589,226	$35,100,171	$17,798,165
9	ISR - Eligible Retirements in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L5×3÷12+[P1]L25+L27+L46×7÷12; Col(b)=[P1]L46×5÷12+[P2]L19×7÷12; Col (c)=[P2]L19×5÷12+L40×7÷12	$20,451,820	$22,665,233	$9,928,809	$593,200	$247,167	$0
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$4,015,632	$21,996,026	$34,853,004	$17,798,165
	Net NOL Position							
11	ISR - (NOL)/Utilization	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2021 ISR Plan Docket No. 4995, Col (c)=Per Tax Departmen	($4,571,409)	$1,506,783	$0	$1,695,589	$730,905	$36,088,700
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	$12,274,232
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 24 of 33, Line 12	($2,998,499)	$991,622	$0	$1,125,232	$482,315	$23,814,468
14	(NOL)/Utilization in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P. 12: Col (c)= L39×7÷12	$0	$0	$1,462,980	$6,764,379	$4,085,281	$0
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$991,622	($1,462,980)	($5,639,147)	($3,602,966)	$23,814,468

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement Reconciliation
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)	23,909,674.21
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												36,088,700.00
14	NOL recovered in transmission rates												12,179,025.79
15	Distribution-related NOL												23,909,674.21

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 23 of 33, Line 13
12	Lesser of Line 10 or Line 11
13	Per Tax Department
14	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 13
15	Line 13 - Line 14

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

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

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

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

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

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

Column Notes:

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

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

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

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

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

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

Compliance Attachment 2
Schedule 6-ELEC
Page 2 of 5

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

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

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

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 1
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**End of FY 2018**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2019**
1	Plant In Service	$1,595,499	$111,243	$3,137	$114,380		($12,016)		$1,697,863
2	Accumulated Depr	$672,116				$52,896	($12,016)	($7,949)	$705,047
3	Net Plant	$923,383							$992,816
4	Property Tax Expense	$30,354							$32,077
5	Effective Prop Tax Rate	3.29%							3.23%
	Effective tax Rate Calculation	**End of FY 2019**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2020**
6	Plant In Service	$1,697,863	$98,620	$8,892	$107,511		($14,649)		$1,790,725
7	Accumulated Depr	$705,047				$54,164	($14,649)	($14,771)	$729,791
8	Net Plant	$992,816							$1,060,934
9	Property Tax Expense	$32,077							$32,568
10	Effective Prop Tax Rate	3.23%							3.07%
	Effective Tax Rate Calculation	**End of FY 2020**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2021**
11	Plant In Service	$1,790,725	$115,360	$3,150	$118,510		($22,589)		$1,886,646
12	Accumulated Depr	$729,791				$57,246	($22,589)	($11,374)	$753,074
13	Net Plant	$1,060,934							$1,133,572
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	$86,464	$13,092	$99,557		($35,100)		$1,951,103
17	Accumulated Depr	$753,074				$59,937	($35,100)	($7,686)	$770,224
18	Net Plant	$1,133,572							$1,180,878
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	$1,951,103	$94,756	$9,926	$104,682		($17,798)		$2,037,987
22	Accumulated Depr	$770,224				$63,590	($17,798)	($8,431)	$807,585
23	Net Plant	$1,180,878							$1,230,402
24	Property Tax Expense	$33,955							$34,532
25	Effective Prop Tax Rate	2.88%							2.81%

The Narragansett Electric Company
d/b/a Rhode Island Energy
Fiscal Year Year 2023 ISR Property Tax Recovery Adjustment 2 (continued)
(000s)

	Property Tax Recovery Calculation	**(a)**	**(b)**	**(c)**	**(d**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**
		Cumulative Increm. ISR Prop. Tax for FY201!			**Cumulative Increm. ISR Prop. Tax for FY201! 1st 5 months**			**Cumulative Increm. ISR Prop. Tax for FY2019 7 months**		
31	Incremental ISR Additions		$92,660			$111,243			$35,209	
32	Book Depreciation: base allowance on ISR eligible plant		($43,032)			($43,032)			$0	
33	Book Depreciation: current year ISR additions		($1,317)			($1,628)			($979)	
34	COR		$9,980			$7,949			$362	
35	Net Plant Additions		$58,291			$74,532			$34,591	
36	RY Effective Tax Rate		3.98%			3.98%			3.28% 1.91%	
37	ISR Year Effective Tax Rate	3.29%			3.23%					
38	RY Effective Tax Rate	3.98%	-0.69%		3.98%	-0.75%		3.23%		
39	RY Effective Tax Rate 5 mos for FY 2019		-0.69%		5 month	-0.31%		3.28%	-0.05%	
40	RY Net Plant times 5 mo rate	$746,900	-0.69%	($5,191)	$746,900	-0.31%	($2,338)		-0.03% 7 mos	
41	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)
42	FY 2015 Net Adds times ISR Year Effective Tax rate	$34,308	3.29%	$1,128	$32,324	1.35%	$435			
43	FY 2016 Net Adds times ISR Year Effective Tax rate	$33,535	3.29%	$1,102	$32,090	1.35%	$432	$17,082	1.88%	$322
44	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	3.29%	$1,256	$37,040	1.35%	$499	$34,591	1.88%	$651
45	FY 2018 Net Adds times ISR Year Effective Tax rate	$58,291	3.29%	$1,916	$55,850	1.35%	$752			
46	FY 2019 Net Adds times ISR Year Effective Tax rate				$74,532	1.35%	$1,003			
47	Total ISR Property Tax Recovery			$263			$800			$694

		(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**		
48	Incremental ISR Additions		$67,435			$115,360			$86,464	
49	Book Depreciation: base allowance on ISR eligible plant		$0			$0			($29,112)	
50	Book Depreciation: current year ISR additions		($1,002)			($1,475)			($815)	
51	COR		$11,333			$10,233			$7,601	
52	Net Plant Additions		$77,766			$124,118			$64,137	
53	RY Effective Tax Rate		3.38%			3.58%			3.66%	
54	ISR Property Tax Recovery on non-ISR									
55	ISR Year Effective Tax Rate	3.07%			2.94%			2.88%		
56	RY Effective Tax Rate	3.38%	-0.31%		3.58%	-0.64%		3.66%	-0.79%	
57	RY Effective Tax Rate 7 mos for FY 2019									
58	RY Net Plant times Rate Difference	$902,404	-0.31%	($2,825)	$853,576	* -0.64%	($5,427)	$833,223	* -0.79%	($6,574)
59	Non-ISR plant times rate difference	($2,269)	-0.31%	$7	($4,269)	* -0.64%	$27	($6,269)	* -0.79%	$49
60	FY 2018 Net Incremental times rate difference	$16,396	3.07%	$503	$15,710	* 2.94%	$462	$15,024	* 2.88%	$432
61	FY 2019 Net Incremental times rate difference	$32,757	3.07%	$1,006	$30,923	* 2.94%	$909	$29,089	* 2.88%	$836
62	FY 2020 Net Incremental times rate difference	$77,766	3.07%	$2,388	$75,762	* 2.94%	$2,228	$73,758	* 2.88%	$2,121
63	FY 2021 Net Incremental times rate difference				$124,118	* 2.94%	$3,650	$121,168	* 2.88%	$3,484
64	FY 2022 Net Adds times rate differenc							$64,137	* 2.88%	$1,844
65	Total ISR Property Tax Recovery			$1,079			$1,850			$2,192

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

		(s)	(t)	(u)
		Cumulative Increm. ISR Prop. Tax for FY2023		
66	Incremental ISR Additions		$94,756	
67	Book Depreciation: base allowance on ISR eligible plant		($49,907)	
68	Book Depreciation: current year ISR additions		($1,216)	
69	COR		$7,773	
70	Net Plant Additions		$51,406	
71	RY Effective Tax Rate		3.66%	
72	ISR Property Tax Recovery on non-ISR			
73	ISR Year Effective Tax Rate	2.81%		
74	RY Effective Tax Rate	3.66%	-0.86%	
75	RY Effective Tax Rate 7 mos for FY 2019			
76	RY Net Plant times Rate Difference	$833,223	* -0.86%	($7,141)
77	Non-ISR plant times rate difference	($8,269)	* -0.86%	$71
78	FY 2018 Net Incremental times rate difference	$14,338	* 2.81%	$402
79	FY 2019 Net Incremental times rate difference	$27,254	* 2.81%	$765
80	FY 2020 Net Incremental times rate difference	$71,754	* 2.81%	$2,014
81	FY 2021 Net Incremental times rate difference	$118,217	* 2.81%	$3,318
82	FY 2022 Net Adds times rate difference	$62,506	* 2.81%	$1,755
83	FY 2023-NG Net Adds times rate difference	$51,406	* 2.81%	$1,443
84	PY 2024-PPL Net Adds times rate difference			
85	Total ISR Property Tax Recovery			$2,628

Line Notes

1(a) - 15(h)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 20,
16(a) - 20(a)	=11(h) - 15(h)
16(b) - 16(d)	Docket No. 5098 Attachment 1C, Page 26 of 29, 16(b) to 16(d)
16(e)	Docket 5098, C. Att. 2, Sch 6-ELEC, P2: (L37(b) + L38(b)) +((, L 6(a) + Page 5 of 33, L 6(a)+Page 10 of 33, L(a)+, L6(a)) × 0.0316+Page 8 of 3333(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 33, Line 3(a) through 3(c) / 1000
21(c)	Per Company's Book
21(d)	Line 21(b) + Line 21(c)
21(f), 22(f)	Per Company's Book
21(h)	Line21(a) + 21(d) + 21(f)
22(e)	Per Company's Book
22(h)	Line22(a) + 22(e) + 22(f) + 22(g)
23(h)	21(h)-22(h)

Line Notes

24(h)	Per Company's Book
25(h)	Line 24(h) ÷ 23(h)
31(a) - 47(i)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
48(j) - 65(o)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
48(q) - 62(r)	Docket No. 5098 Attachment 1C, Page 26 of 29, 38(j) to 50(k)
63(p)	=63(m) - (Page 13 of 33, Line 19(b) ÷ 1000
64(p)	=52(q)
63(q) - 64(q)	=55(p)
63(r) - 64(r)	=63(p) to 64(p) x 63(q) to 64(q)
65(r)	Sum of Lines 58(r) through 64(r)
66(t)	Page 20 of 33, Line 3(a) through 3(c) / 1000
67(t)	Page 20 of 33, Line 8(a) through 8(c) / 1000
68(t)	Page 20 of 33, Line 19(a) through 19(c) /1000
69(t)	Page 20 of 33, Line 10(a) through 10(c) / 1000
70(t)	Sum of Lines 66(t) through 69(t)
71(t)	=53(q)
73(s)	=25(h)

Line Notes

74(s)	=71(t)
74(t)	73(s) -74(s)
76(s)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000]
77(s)	=59(p) - 2000
78(s)	=60(p) - (Page 2 of 33, Line 19(i) / 1000
79(s)	=61(p) - (Page 5 of 33, Line 19(e) + Page 8 of 33, Line 33(o))/1000
80(s)	=62(p) - (Page 10 of 33, Line 19(d) through 19(f) / 1000
81(s)	=63(p) - (Page 13 of 33, Line 19(c) through 19(e) / 1000
82(s)	=64(p) - (Page 17 of 33, Line 19(b) through 19(d) / 1000
83(s)	=70(t)
76(t)-77(t)	=74(t)
78(t)-83(t)	=73(s)
76(u) - 83(u)	=76(s) to 83(s) x 76(t) to 83(t)
85(u)	Sum of Lines 76(u) through 83(u)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2023 Electric ISR Revenue Requirement 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 2023 Incremental Capital Investment

Line No.			Fiscal Year 2023 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in FY 2023 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	FY 2023 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 18, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$41,435,783**	**$0**	$41,435,783
	Discretionary Capital				
2	Cumulative FY 2022 Discretionary Capital ADDITIONS	Docket 4915 + Docket 4995	$513,121,351		
3	FY 2023 Discretionary Capital ADDITIONS	Section 2, Chart 18, Col 2	$53,320,145		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$566,441,496		
5	Cumulative FY 2022 Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$550,976,033		
6	FY 2023 Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$63,316,000		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$614,292,033		
8	Cumulative FY 2022 Approved Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$552,491,536		
9	FY 2023 Approved Discretionary Capital SPENDING	Section 2, Chart 18, Col 1	$63,316,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$615,807,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$566,441,496		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Docket No. 4915 -ISR Plan Reconciliation	$513,121,351		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$53,320,145**	**$0**	**$53,320,145**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$94,755,928**	**$0**	**$94,755,928**
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			**$94,755,928**

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

Line No.		Actual-Revised Fiscal Year 2018 (a)	Actual-Revised Fiscal Year 2019 (b)	Actual-Revised Fiscal Year 2020 (c)	Actual-Revised Fiscal Year 2021 (d)	Actual-Revised Fiscal Year 2022 (e)	
	Capital Investment:						
1	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$1,059,288	$2,060,611	$1,984,661	$1,931,906	$1,879,763	
2	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		$1,521,500	$4,332,013	$4,165,495	$4,012,227	
3	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			$2,368,560	$5,638,935	$5,436,943	
4	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				$4,393,352	$8,635,547	
5	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					$2,395,558	
6	Subtotal	$1,059,288	$3,582,110	$8,685,233	$16,129,689	$22,360,037	
7	Property Tax Recovery Adjustment	$263,025	$1,493,525	$1,079,265	$1,850,478	$2,191,610	
8	**Total Capital Investment Component of Revenue Requirement**	**$1,322,314**	**$5,075,635**	**$9,764,498**	**$17,980,167**	**$24,551,648**	
		As Filed	**As Filed**	**As Filed**	**As Filed**	**As Filed**	
		Fiscal Year 2018	**Fiscal Year 2019**	**Fiscal Year 2020**	**Fiscal Year 2021**	**Fiscal Year 2022**	
	Capital Investment:						
9	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	1,127,881	2,194,101	2,113,261	2,057,064	2,001,528	
10	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		1,554,589	4,442,470	4,272,396	4,115,669	
11	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			2,611,228	6,144,268	5,927,885	
12	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				4,454,380	8,755,906	
13	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					2,518,888	
14	Subtotal	$1,127,881	$3,748,690	$9,166,959	$16,928,109	$23,319,877	
15	Property Tax Recovery Adjustment	263,025	1,535,365	1,284,021	2,099,008	2,437,327	
16	**Total Capital Investment Component of Revenue Requirement**	**$1,390,906**	**$5,284,055**	**$10,450,981**	**$19,027,117**	**$25,757,204**	
		Variance Fiscal Year 2018	**Variance Fiscal Year 2019**	**Variance Fiscal Year 2020**	**Variance Fiscal Year 2021**	**Variance Fiscal Year 2022**	
	Capital Investment:						
17	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	(68,593)	(133,490)	(128,600)	(125,158)	(121,765)	
18	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base		(33,089)	(110,458)	(106,901)	(103,442)	
19	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base			(242,668)	(505,333)	(490,942)	
20	Actual Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base				(61,028)	(120,359)	
21	Actual Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base					(123,330)	
22	Actual Revenue Requirement on FY 2023 Incremental Capital included in ISR Rate Base						
23	Subtotal	($68,593)	($166,579)	($481,726)	($798,420)	($959,839)	
24	Property Tax Recovery Adjustment	-	(41,840)	(204,756)	(248,530)	(245,717)	
25	**Total Capital Investment Component of Revenue Requirement - DG Adjustment**	**($68,593)**	**($208,420)**	**($686,482)**	**($1,046,950)**	**($1,205,556)**	**($3,216,001)**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Impact of Elimination of ADIT and Hold Harmless Commitment for the FY 2023 Reconciliation
Fiscal Year 2023 - April 2022-March 2023

Inputs

1	Tax Rate		21.00%	
	Gas and Distribution			
2	Long Term Debt		48.350%	
3	Short Term Debt		0.600%	
4	Preferred Stock		0.100%	
5	Debt Weighting	Lines 2+3+4	49.050%	
6	Equity Weighting	1 - Line 5	50.950%	
7	Long Term Debt Rate		4.620%	
8	Short Term Debt Rate		1.760%	
9	Cost of Debt	Line 2 / Line 5 * Line 7 + Line 3 / Line 5 * Line 8	4.585%	
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)	$ 210,141,268	Fiscal Year 2023
14	Rate Base - NG (before sale)	Page 2. Line 9, Column (f)	$ 200,916,076	Fiscal Year 2023
15	**Deferred Taxes / Hold Harmless**	**Lines 8 - 9**	**$ 9,225,192**	Elimination of Deferred Taxes

Distribution ROE Mechanics

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

			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	210,141,268	210,141,268	-	
17	ADIT Adjustment	- Line 15	-	(9,225,192)	9,225,192	
18	**Adjusted Rate Base**	**Lines 16 + 17**	**210,141,268**	**200,916,076**	**9,225,192**	
19	Debt Return (4.576%)	Lines 18 * 5 * 9	4,725,899	4,518,432	207,467	
20	Equity Return (9.275%)	Lines 18 * 6 * 10	9,930,462	9,494,515	435,947	
21	Taxes on Equity (21%)	(Line 20 / (1 - Line 1)) * Line 1	2,639,743	2,523,858	115,885	
22	**Total Unadjusted Revenue**	**Sum of Lines 19 , 20, 21**	**17,296,104**	**16,536,806**	**759,298**	
23	Revenue Adjustment for Fiscal Year 2023	- Line 15 * Line 11	(759,233)	-	(759,233)	Note 1
24	**Total Revenue**	**Lines 23 + 24**	**16,536,870**	**16,536,806**	**65**	
25	Interest Expense	Lines 18, Col (b) * 5 * 9	4,518,432	4,518,432	-	
26	Tax Expense	(Lines 24 - 25) * Line 1	2,523,872	2,523,858	14	
27	**Net Income**	**Lines 24 - 25 - 26**	**9,494,566**	**9,494,515**	**51**	
	Impact of Transaction					
28	Transaction-related Tax Deduction	- Line 23 * Line 1 / (1-Line 1)	2,856,163			
29	Cash Tax Benefit at 21%	Line 28 * Line 1	599,794			
30	Cash Tax Benefit Grossed Up	Line 29 / (1-Line 1)	759,233			

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

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

		Post-Acquisition (a)	Prorated (b)	Post-Acquisition After Proration (c)		No Acquisition (d)	Prorated (e)	No Acquisition After Proration (f)	
1	**Plan Year 2023**								
2	FY 2018	13,601,489	100%	13,601,489		13,877,314	100%	13,877,314	
3	FY 2019	25,185,784	100%	25,185,784		23,604,811	100%	23,604,811	
4	FY 2019 Intangible	1,649,877	100%	1,649,877		1,076,585	100%	1,076,585	
5	FY 2020	41,505,326	100%	41,505,326		39,320,907	100%	39,320,907	
6	FY 2021	67,609,717	100%	67,609,717		65,456,511	100%	65,456,511	
7	FY 2022	39,871,378	100%	39,871,378		37,291,953	100%	37,291,953	
8	FY 2023	20,717,697	100%	20,717,697		20,287,995	100%	20,287,995	
9		210,141,268		210,141,268	Page 2, Line 13	200,916,076		200,916,076	Page 2, Line 14

PRE-FILED DIRECT TESTIMONY

OF

TYLER G. SHIELDS

August 1, 2023

Table of Contents

I. Introduction and Qualifications

Q. Please state your name and business address.

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

Q. Please state your position.

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

Q. Please describe your educational background.

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

Q. Please describe your professional background.

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

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

A. Yes, I provided pre-filed direct testimony in the Company's Fiscal Year 2023 Electric Revenue Decoupling Mechanism Reconciliation Filing, Docket No. 23-16-EL and the Company's Gas Revenue Decoupling Mechanism (RDM) Reconciliation filing in Docket No. 23-23-NG.

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

Q. What is the purpose of your testimony?

A. My testimony presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the Company's Infrastructure, Safety, and Reliability Provision, R.I.P.U.C. No. 2199 effective September 1, 2018 ("ISR Provision"), resulting from the reconciliation of actual costs and revenue associated with the Fiscal Year ("FY") 2023 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 2023 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 2021 CapEx and O&M reconciliations;
- the status of the credit of the FY 2022 CapEx and O&M reconciliations;
- the calculation of the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2023; 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 2023 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2023 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 2021 CapEx net over-recovery reconciliation balance as well as the status of the return to customers of the FY 2022 CapEx net over-recovery reconciliation balance;
- Section V presents the results of the FY 2023 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the final status of the return to customers of the FY 2021 O&M over-recovery reconciliation balance as well as the status of the return to customers of the FY 2022 O&M over-recovery reconciliation balance; and
- Section VI presents the rate class bill impact analysis.

III. Summary of FY 2023 Capex and O&M Reconciliations

Q. Please summarize the results of the FY 2023 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2023 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 Witnesses Stephanie A. Briggs and Jeffrey D. Oliveira. As reflected in Attachment TGS-1, the result of the CapEx reconciliation is a net over-recovery of approximately $8.8 million; the result of the O&M reconciliation is a net under-recovery of approximately $1.3 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 the upcoming year, the Company determines the CapEx Factors, which are designed to recover the revenue requirement on the forecasted capital investment for the ISR Plan’s investment year plus cumulative capital investment in prior years’ ISR Plans, as well as the O&M Factors based on the forecasted O&M expense for the Plan year. On an annual basis, the Company is required to reconcile the annual CapEx revenue requirement on actual cumulative ISR capital investment and the actual O&M expense incurred to actual billed revenue generated from the CapEx Factors and the O&M Factors, respectively. The over or under-recovered balances resulting from the CapEx and O&M reconciliations are either credited to or recovered from customers through the CapEx Reconciling Factors and the O&M Reconciling Factor, respectively.

IV. Capex Reconciliation and Proposed Capex Reconciling Factors

Q. What is the result of the CapEx reconciliation for FY 2023?

A. The FY 2023 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, 2022 through March 31, 2023 of approximately $35.1 million. Line (4) reflects the CapEx revenue requirement on actual cumulative ISR capital investment of approximately $26.3 million. Line (6) identifies the net over-recovery by rate class of the CapEx revenue requirement, which totals approximately $8.8 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 2023 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 over-recovery of approximately $8.8 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 under-recovery resulting from the FY 2021 CapEx reconciliation. The net recovery of the FY 2021 CapEx reconciliation balance is presented on page 3. Of the $2.4 million net over-recovery for FY 2021 to be returned to customers via CapEx Reconciling Factors approved by the PUC, the Company returned to customers $2.5 million from October 1, 2021 through September 30, 2022. The remaining balance is a net under-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' residual balance associated with the FY 2021 reconciliation as an adjustment to the FY 2023 CapEx reconciliation balance.

Q. How is the Company proposing to credit the FY 2023 CapEx net over-recovery?

A. The Company is proposing to implement a CapEx Reconciling Factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment TGS-2, page 1. The over or under-recovery by rate class on Line (8) is divided by each rate class' forecasted kWh deliveries for the period October 1, 2023 through September 30, 2024 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 2022 CapEx reconciliation?

A. Yes. The status of the FY 2022 CapEx reconciliation net over-recovery balance is presented in Attachment TGS-2, page 4. As of June 30, 2023, the balance reflects a remaining net over-recovery of approximately $1.8 million, which the Company will continue to return to customers through September 30, 2023.

Q. Did the Company adjust the FY 2022 CapEx reconciliation net over-recovery balance?

A. Yes. The Company adjusted the FY 2022 CapEx reconciliation net over-recovery balance from $4,779,760 to $4,708,094.

Q. Why did the Company adjust the FY 2022 CapEx reconciliation net over-recovery balance?

A. In the preparation of its schedules in the instant proceeding, the Company identified that it had incorrectly used March 2022 billed kilowatt-hours instead of April 2022 billed kilowatt-hours in the calculation of CapEx Factor and CapEx Reconciliation Factor revenues associated with kilowatt-hours consumed prior to April 1, 2022. The incorrect use of March 2022 billed kilowatt-hours instead of April 2022 billed kilowatt-hours in this calculation overstated the Company's revenues by approximately $71,666, and thereby overstated the FY 2022 CapEx reconciliation net over-recovery balance by this same amount. The Company's adjustment corrects this overstatement and its detailed calculation is presented as Attachment TGS-5.

Q. How will the Company propose to credit or recover any residual balances as of September 30, 2023?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the CapEx Reconciling Factors is subject to reconciliation. Therefore, the Company will present the final reconciliation of balances from the FY 2022 CapEx reconciliation in the FY 2024 ISR Plan Reconciliation Filing and include each rate class' residual balance from the FY 2022 CapEx reconciliation with the balances resulting from the FY 2024 CapEx reconciliation and will propose CapEx Reconciling Factors on the total.

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

Q. What is the result of the O&M reconciliation for FY 2023?

A. The O&M reconciliation for FY 2023 is presented in Attachment TGS-3, page 1. Line (1) shows the actual O&M expense for FY 2023 of approximately $13.7 million, which is supported in the testimony of Company Witnesses Stephanie A. Briggs and Jeffrey D. Oliveira. Line (2) shows O&M revenue billed through the O&M Factors from April 1, 2022 through March 31, 2023 of approximately $12.5 million. Line (3) shows the difference of approximately $1.3 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 over-recovery resulting from the FY 2021 O&M reconciliation. The return to customers of the over-recovered balance is presented on page 3. Of the $743,647 over-recovery that formed the basis for the O&M Reconciling Factor approved by the PUC, the Company returned to customers $739,578 from October 1, 2021 through September 30, 2022, leaving $4,069 to yet be returned to customers. As described in Docket No. 4682, the Company is including the residual balance as an adjustment to the FY 2023 O&M reconciliation balance.

Q. Please describe the amount included on Line (5).

A. The amount presented on Line (5) reflects the carry forward of the over-recovery balance resulting from the FY 2022 O&M reconciliation. In Docket No. 5098, this over-recovery balance of $69,828, resulting from the FY 2022 O&M reconciliation, was too small to generate a billable factor and so the Company proposed to carry this over-recovery amount forward into the next Annual ISR reconciliation filing.[1] The Company proposes to include this carry forward amount as an adjustment to the FY 2023 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 $1,193,683on Line (5) is divided by

[1] *See* R.I.P.U.C. Docket No. 5098, FY 2022 Electric Infrastructure, Safety, and Reliability Plan Annual Reconciliation Filing, Pre-Filed Direct Testimony of Peter R. Blazunas, Page 9 of 11, Lines 15 through 20.

the forecasted kWh during the period October 1, 2023 through September 30, 2024, on Line (6), resulting in a charge of 0.016¢ 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 over-recovery of the FY 2022 O&M reconciliation?

A. Yes. The status of the balance from the FY 2022 O&M reconciliation is presented in Attachment TGS-3, page 4. As discussed above, the FY 2022 O&M reconciliation resulted in an over-recovery balance that was too small to generate a billable factor. Hence, for the period October 1, 2022 through September 30, 2023, there is no O&M Reconciling Factor in place to return this amount to customers. Consequently, the Company proposes to include this over-recovery balance as an adjustment to the FY 2023 O&M reconciliation balance.

Q. How does the Company propose to credit or recover the residual balance at September 30, 2023?

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 would typically present the final reconciliation of the balance from the FY 2022 O&M reconciliation in the FY 2024 ISR Reconciliation Filing and include the residual balance of the FY 2022 O&M reconciliation with the results of the FY 2024 O&M reconciliation and would propose an O&M Reconciling Factor on the total. In this instance, however, the Company is proposing to include the carry forward FY 2022 over-recovery balance as an adjustment to the FY 2023 O&M reconciliation balance. Consequently, this treatment of the FY 2022 over-recovery balance effectively serves as a final reconciliation of this balance.

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 ($0.00148) per kWh and the proposed O&M Reconciling Factor of $0.00016 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is a decrease of $0.23, or approximately 0.2%, from $134.24 to $134.01.

VII. Summary of Retail Delivery Rates

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

A. No, not at this time. The Company will also be submitting its Pension and Post-retirement Benefits Other than Pension Adjustment Factor ("PAF") filing in August 2023 in which the Company will propose a PAF, effective October 1, 2023. The Company has also submitted a Renewable Energy ("RE") Growth Factor Filing with proposed factors also effective October 1, 2023. The Company will file a Summary of Retail Delivery Rates tariff reflecting all rates proposed for October 1, 2023 in compliance with the PUC's orders in this proceeding and the PAF and the RE Growth proceedings.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment TGS-1

FY 2023 ISR Plan Annual Reconciliation Summary

FY 2023 ISR Plan Annual Reconciliation Summary

		CapEx	O&M	Total
		(a)	(b)	(c)
(1)	Actual Revenue Requirement	$26,299,920	$13,731,126	$40,031,046
(2)	Revenue Billed	$35,071,613	$12,463,546	$47,535,159
(3)	Total Over/(Under) Recovery	$8,771,693	($1,267,580)	$7,504,113

(1)	Column (a): Attachment SAB/JDO-1, Page 1 of 33:		
	Line (14), Column (b): Total Capital Investment Component of Revenue Requirement	$	30,275,153
	Line (16), Column (b): Per Tax Hold Harmless Adjustment	$	(759,233)
	Line (18), Column (b): Adjustment for DG Project Review	$	(3,216,001)
	Total Net Capital Investment Component of Revenue Requirement	$	26,299,920
	Column (b): Attachment SAB/JDO-1, Page 1 of 33, 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 2023 ISR Plan
For the Recovery/(Refund) Period October 1, 2023 through September 30, 2024

		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	Lighting S-05/S-06 S-10/S-14 (f)	Propulsion X-01 (g)
(1)	Actual FY2023 Capital Investment Revenue Requirement	$26,299,920						
(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 FY2023 Capital Investment Revenue Requirement	$26,299,920	$14,600,632	$2,704,179	$4,223,600	$4,464,928	$299,082	$7,499
(5)	CapEx Revenue Billed	$35,071,613	$19,336,311	$3,130,945	$5,890,302	$6,361,184	$338,291	$14,580
(6)	Total Over/(Under) Recovery for FY 2023	$8,771,693	$4,735,679	$426,767	$1,666,702	$1,896,256	$39,209	$7,081
(7)	Remaining Over/(Under) For FY 2021	($66,518)	($51,151)	$7,898	($8,776)	($8,253)	($5,059)	($1,177)
(8)	Total Over/(Under) Recovery	$8,705,175	$4,684,528	$434,665	$1,657,926	$1,888,003	$34,150	$5,904
(9)	Forecasted kWhs - October 1, 2023 through September 30, 2024	7,324,058,339	3,154,863,223	702,485,422	1,198,036,737	2,213,658,401	37,762,917	17,251,639
(10)	Proposed Class-specific CapEx Reconciling Factor Charge/(Credit) per kWh		($0.00148)	($0.00061)	($0.00138)	($0.00085)	($0.00090)	($0.00034)

(1) Column (a): Attachment SAB/JDO-1, Page 1 of 33:

Line (14), Column (b): Total Capital Investment Component of Revenue Requirement	$	30,275,153
Line (16), Column (b): Per Tax Hold Harmless Adjustment	$	(759,233)
Line (18), Column (b): Adjustment for DG Project Review	$	(3,216,001)
Total Net Capital Investment Component of Revenue Requirement	$	26,299,920

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

Fiscal Year 2023 CapEx Reconciliation
For the Period April 1, 2022 through March 31, 2023
For the Recovery/Refund Period October 1, 2023 through September 30, 2024

CapEx Revenue By Rate Class:

	Month	Residential A-16 / A-60 Total Revenue (a)	Residential CapEx Rec Factor Revenue (b)	Residential Base Revenue (c)	Small C&I C-06 Total Revenue (a)	Small C&I CapEx Rec Factor Revenue (b)	Small C&I Base Revenue (c)
(1)	Apr-22	$ 512,213.00	$ (63,183)	$575,396	$ 71,095.00	$ 3,181	$67,914
	May-22	$ 1,138,817.00	($138,037)	$1,276,854	$ 232,094.00	$7,373	$224,721
	Jun-22	$ 1,233,027.00	($149,289)	$1,382,316	$ 242,649.00	$7,419	$235,230
	Jul-22	$ 1,769,511.00	($214,238)	$1,983,749	$ 292,241.00	$8,789	$283,452
	Aug-22	$ 2,210,673.00	($267,638)	$2,478,311	$ 324,293.00	$9,416	$314,877
	Sep-22	$ 1,864,330.00	($225,717)	$2,090,047	$ 319,761.00	$8,937	$310,824
	Oct-22	$ 1,142,117.00	($157,124)	$1,299,241	$ 244,160.00	$2,536	$241,624
	Nov-22	$ 1,132,457.00	($183,185)	$1,315,642	$ 227,932.00	($3,670)	$231,602
	Dec-22	$ 1,224,818.00	($198,210)	$1,423,028	$ 217,797.00	($3,587)	$221,384
	Jan-23	$ 1,534,717.00	($248,377)	$1,783,094	$ 281,298.00	($4,183)	$285,481
	Feb-23	$ 1,282,390.00	($207,548)	$1,489,938	$ 256,445.00	($3,983)	$260,428
	Mar-23	$ 1,247,987.00	($201,972)	$1,449,959	$ 256,744.00	($4,104)	$260,848
(2)	Apr-23	$ 678,881.00	$ (109,855)	$788,736	$ 190,078.00	$ (2,482)	$192,560
	Total	$16,971,938	($2,364,373)	$19,336,311	$3,156,587	$25,642	$3,130,945

	Month	General C&I G-02 Total Revenue (a)	General C&I CapEx Rec Factor Revenue (b)	General C&I Base Revenue (c)	Demand B-32 / G-32 Total Revenue (a)	Demand CapEx Rec Factor Revenue (b)	Demand Base Revenue (c)
(1)	Apr-22	$ 187,259.00	$ (4,967)	$192,226	$ 40,161.00	$ (9,894)	$50,055
	May-22	$ 449,967.00	($11,106)	$461,073	$ 459,978.00	($22,654)	$482,632
	Jun-22	$ 440,787.00	($11,245)	$452,032	$ 494,857.00	($24,037)	$518,894
	Jul-22	$ 480,306.00	($12,873)	$493,179	$ 501,288.00	($24,290)	$525,578
	Aug-22	$ 515,008.00	($14,717)	$529,725	$ 599,797.00	($29,071)	$628,868
	Sep-22	$ 518,149.00	($14,230)	$532,379	$ 563,642.00	($27,820)	$591,462
	Oct-22	$ 569,461.00	($43,764)	$613,225	$ 500,061.00	($50,602)	$550,663
	Nov-22	$ 430,571.00	($69,664)	$500,235	$ 415,254.00	($76,538)	$491,792
	Dec-22	$ 375,613.00	($66,851)	$442,464	$ 451,293.00	($84,179)	$535,472
	Jan-23	$ 408,726.00	($73,704)	$482,430	$ 425,817.00	($80,010)	$505,827
	Feb-23	$ 401,022.00	($69,051)	$470,073	$ 392,450.00	($67,301)	$459,751
	Mar-23	$ 394,246.00	($69,080)	$463,326	$ 449,008.00	($82,327)	$531,335
(2)	Apr-23	$ 218,950.00	$ (38,985)	$257,935	$ 438,967.00	$ (49,888)	$488,855
	Total	$5,390,065	($500,237)	$5,890,302	$5,732,573	($628,611)	$6,361,184

	Month	Lighting S-05/S-06/S-10/S-14 Total Revenue (a)	Lighting CapEx Rec Factor Revenue (b)	Lighting Base Revenue (c)	Propulsion X-01 Total Revenue (a)	Propulsion CapEx Rec Factor Revenue (b)	Propulsion Base Revenue (c)
(1)	Apr-22	$ 15,968.00	$ 753	$15,215	$ 236.00	$ (131)	$367
	May-22	$ 25,197.00	$1,306	$23,891	$ 696.00	($321)	$1,017
	Jun-22	$ 33,556.00	$1,843	$31,713	$ 808.00	($369)	$1,177
	Jul-22	$ 22,707.00	$1,120	$21,587	$ 813.00	($371)	$1,184
	Aug-22	$ 22,580.00	$1,072	$21,508	$ 842.00	($384)	$1,226
	Sep-22	$ 24,460.00	$1,163	$23,297	$ 934.00	($426)	$1,360
	Oct-22	$ 33,410.00	$1,486	$31,924	$ 834.00	($327)	$1,161
	Nov-22	$ 27,107.00	$981	$26,126	$ 977.00	($262)	$1,239
	Dec-22	$ 27,360.00	$724	$26,636	$ 1,143.00	($302)	$1,445
	Jan-23	$ 39,423.00	$1,506	$37,917	$ 936.00	($247)	$1,183
	Feb-23	$ 37,954.00	$1,497	$36,457	$ 1,014.00	($268)	$1,282
	Mar-23	$ 31,478.00	$1,326	$30,152	$ 946.00	($250)	$1,196
(2)	Apr-23	$ 12,340.00	$ 472	$11,868	$ 588.00	$ (155)	$743
	Total	$353,540	$15,249	$338,291	$10,767	($3,813)	$14,580

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

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
R.I.P.U.C. Docket No. 5209
FY 2023 Electric Infrastructure, Safety,
and Reliability Plan Reconciliation Filing
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The Narragansett Electric Company
d/b/a Rhode Island Energy
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and Reliability Plan Reconciliation Filing
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Fiscal Year 2021 CapEx Reconciliation of Under Recovery
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

		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	$2,404,073		$2,083,030		($85,823)		$139,972		$288,697
(2)	CapEx Reconciling Factors			($0.00069)		$0.00013		($0.00012)		($0.00013)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-21	($80,119)	98,605,668	($68,038)	22,993,282	$2,989	42,314,832	($5,078)	81,422,147	($10,585)
	Nov-21	($157,070)	190,381,543	($131,363)	48,889,383	$6,356	91,042,777	($10,925)	173,647,566	($22,574)
	Dec-21	($193,644)	241,544,671	($166,666)	55,513,579	$7,217	95,417,392	($11,450)	185,393,324	($24,101)
	Jan-22	($213,680)	269,943,916	($186,261)	57,064,601	$7,418	97,368,925	($11,684)	190,461,789	($24,760)
	Feb-22	($218,156)	275,925,654	($190,389)	62,419,470	$8,115	107,533,315	($12,904)	186,394,762	($24,231)
	Mar-22	($190,677)	237,585,313	($163,934)	60,919,900	$7,920	103,690,927	($12,443)	189,940,474	($24,692)
	Apr-22	($177,798)	219,302,240	($151,319)	58,598,144	$7,618	99,132,350	($11,896)	182,235,879	($23,691)
	May-22	($163,439)	200,054,146	($138,037)	56,711,733	$7,373	92,548,324	($11,106)	174,258,561	($22,654)
	Jun-22	($175,678)	216,361,105	($149,289)	57,067,906	$7,419	93,712,264	($11,245)	184,897,219	($24,037)
	Jul-22	($241,863)	310,490,206	($214,238)	67,608,069	$8,789	107,273,264	($12,873)	186,842,487	($24,290)
	Aug-22	($301,322)	387,881,451	($267,638)	72,433,009	$9,416	122,642,491	($14,717)	223,624,262	($29,071)
	Sep-22	($258,093)	327,126,026	($225,717)	68,746,634	$8,937	118,581,448	($14,230)	213,997,458	($27,820)
(4)	Oct-22	($99,052)	117,814,889	($81,292)	31,951,672	$4,154	68,305,796	($8,197)	111,105,443	($14,444)
(5)	Total	($2,470,591)		($2,134,181)		$93,721		($148,748)		($296,950)
(6)	Ending Over/(Under) Recovery	($66,518)		($51,151)		$7,898		($8,776)		($8,253)

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		($24,723)		$2,920
(2)	CapEx Reconciling Factors		$0.00051		($0.00021)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-21	1,424,078	$726	634,095	($133)
	Nov-21	3,427,078	$1,748	1,486,229	($312)
	Dec-21	3,317,832	$1,692	1,601,387	($336)
	Jan-22	3,761,764	$1,918	1,480,858	($311)
	Feb-22	3,051,917	$1,556	1,440,742	($303)
	Mar-22	5,429,953	$2,769	1,413,298	($297)
	Apr-22	3,534,580	$1,803	1,489,697	($313)
	May-22	2,560,151	$1,306	1,530,465	($321)
	Jun-22	3,613,012	$1,843	1,756,149	($369)
	Jul-22	2,195,726	$1,120	1,766,505	($371)
	Aug-22	2,101,671	$1,072	1,829,409	($384)
	Sep-22	2,279,890	$1,163	2,030,419	($426)
(4)	Oct-22	1,859,367	$948	1,051,807	($221)
(5)	Total		$19,664		($4,097)
(6)	Ending Over/(Under) Recovery		($5,059)		($1,177)

(1) Docket No. 4995, Attachment DEG-2, Page 1, Line (8)
(2) Docket No. 4995, Attachment DEG-2, Page 1, Line (10)
(3) Prorated for usage on and after October 1, 2021
(4) Prorated for usage prior to October 1, 2022
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
R.I.P.U.C. Docket No. 5209
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Fiscal Year 2022 CapEx Reconciliation of Over Recovery
For the Period April 1, 2021 through March 31, 2022
For the Recovery/Refund Period October 1, 2022 through September 30, 2023

		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery	$4,708,094		$ 2,779,938		$42,790		$895,217		$1,011,808
(2)	CapEx Reconciling Factors			($0.00089)		($0.00007)		($0.00072)		($0.00045)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-22	($148,743)	85,204,022	($75,832)	23,107,529	($1,618)	49,398,923	($35,567)	80,351,734	($36,158)
	Nov-22	($332,338)	205,825,860	($183,185)	52,434,803	($3,670)	96,756,177	($69,664)	170,085,475	($76,538)
	Dec-22	($352,405)	222,707,568	($198,210)	51,238,186	($3,587)	92,848,832	($66,851)	187,064,579	($84,179)
	Jan-23	($405,015)	279,075,594	($248,377)	59,757,823	($4,183)	102,366,040	($73,704)	177,799,964	($80,010)
	Feb-23	($346,654)	233,200,351	($207,548)	56,902,348	($3,983)	95,904,722	($69,051)	149,557,169	($67,301)
	Mar-23	($356,407)	226,935,035	($201,972)	58,631,401	($4,104)	95,944,730	($69,080)	182,947,833	($82,327)
	Apr-23	($352,518)	216,593,423	($192,768)	62,227,398	($4,356)	95,012,227	($68,409)	194,534,902	($87,541)
	May-23	($321,364)	186,093,205	($165,623)	52,966,249	($3,708)	94,538,877	($68,068)	186,734,153	($84,030)
	Jun-23	($331,847)	201,183,955	($179,054)	59,195,688	($4,144)	93,063,487	($67,006)	184,344,967	($82,955)
	Jul-23	$0	-	$0	-	$0	-	$0	-	$0
	Aug-23	$0	-	$0	-	$0	-	$0	-	$0
	Sep-23	$0	-	$0	-	$0	-	$0	-	$0
(4)	Oct-23	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	($2,947,291)		($1,652,569)		($33,353)		($587,400)		($681,039)
(6)	Ending Over/(Under) Recovery	$1,760,803		$1,127,369		$9,437		$307,817		$330,769

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		($23,974)		$2,314
(2)	CapEx Reconciling Factors		$0.00040		($0.00014)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-22	1,344,699	$538	760,670	($106)
	Nov-22	2,452,601	$981	1,868,983	($262)
	Dec-22	1,810,938	$724	2,156,486	($302)
	Jan-23	3,765,334	$1,506	1,765,773	($247)
	Feb-23	3,743,421	$1,497	1,912,668	($268)
	Mar-23	3,314,688	$1,326	1,785,069	($250)
	Apr-23	2,070,163	$828	1,946,335	($272)
	May-23	(530,232)	($212)	(1,979,583)	$277
	Jun-23	3,972,139	$1,589	1,975,517	($277)
	Jul-23	-	$0	-	$0
	Aug-23	-	$0	-	$0
	Sep-23	-	$0	-	$0
(4)	Oct-23	-	$0	-	$0
(5)	Total		$8,777		($1,707)
(6)	Ending Over/(Under) Recovery		($15,197)		$607

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

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

Attachment TGS-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2022 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2023 ISR Plan
For the Recovery/(Refund) Period October 1, 2023 through September 30, 2024

(1)	Actual FY 2023 O&M Revenue Requirement	$13,731,126
(2)	O&M Revenue Billed	$12,463,546
(3)	Total Over/(Under) Recovery for FY 2023	($1,267,580)
(4)	Remaining Over/(Under) For FY 2021	$4,069
(5)	Carry Forward of FY 2022 Over-Recovery	$69,828
(6)	Total Over/(Under) Recovery	($1,193,683)
(7)	Forecasted kWhs - October 1, 2023 through September 30, 2024	7,324,058,339
(8)	Proposed O&M Reconciling Factor Charge/(Credit) per kWh	$0.00016

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

Fiscal Year 2023 Operations & Maintenance Reconciliation
For the Period April 1, 2022 through March 31, 2023
For the Recovery/Refund Period October 1, 2023 through September 30, 2024

O&M Factor Revenue:

	Month	O&M Revenue (a)	Prior Period Reconciliation Factor Revenue (b)	Base O&M Revenue (c)
(1)	Apr-22	$369,031	($21,541)	$390,572
	May-22	$828,335	($52,766)	$881,101
	Jun-22	$889,076	($55,741)	$944,817
	Jul-22	$1,104,775	($67,618)	$1,172,393
	Aug-22	$1,328,651	($81,051)	$1,409,702
	Sep-22	$1,192,441	($73,276)	$1,265,717
	Oct-22	$927,948	($33,209)	$961,157
	Nov-22	$898,031	$0	$898,031
	Dec-22	$934,088	$0	$934,088
	Jan-23	$1,110,612	$0	$1,110,612
	Feb-23	$966,359	$0	$966,359
	Mar-23	$974,471	$0	$974,471
(2)	Apr-23	$554,526	$0	$554,526
	Total	$12,078,344	($385,202)	$12,463,546

(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 2021 O&M Reconciliation of Over Recovery
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

		Total	
(1)	Over/(Under) Recovery	$743,647	
(2)	O&M Reconciling Factor	($0.00010)	
		Total kWhs (a)	Total Revenue (b)
(3)	Oct-21	247,394,103	($24,739)
	Nov-21	508,874,576	($50,887)
	Dec-21	582,788,185	($58,279)
	Jan-22	620,081,853	($62,008)
	Feb-22	636,765,860	($63,677)
	Mar-22	598,979,865	($59,898)
	Apr-22	564,292,890	($56,429)
	May-22	527,663,380	($52,766)
	Jun-22	557,407,655	($55,741)
	Jul-22	676,176,257	($67,618)
	Aug-22	810,512,293	($81,051)
	Sep-22	732,761,875	($73,276)
(4)	Oct-22	332,088,975	($33,209)
(5)	Total	7,395,787,767	($739,578)
(6)	Ending Over/(Under) Recovery		$4,069

(1) Docket No. 4995, Attachment DEG-3 page 1, line (5)
(2) Docket No. 4995, Attachment DEG-3 page 1, line (7)
(3) Reflects kWhs consumed on and after October 1
(4) Reflects kWhs consumed prior to October 1
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

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

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

		Total	
(1)	Over/(Under) Recovery	$69,828	
(2)	O&M Reconciling Factor	$0.00000	
		Total kWhs (a)	Total Revenue (b)
(3)	Oct-22	240,167,576	$0
	Nov-22	529,423,899	$0
	Dec-22	557,826,589	$0
	Jan-23	624,530,528	$0
	Feb-23	541,220,679	$0
	Mar-23	569,558,756	$0
	Apr-23	572,384,448	$0
	May-23	517,822,669	$0
	Jun-23	543,735,753	$0
	Jul-23	-	$0
	Aug-23	-	$0
	Sep-23	-	$0
(4)	Oct-23	-	$0
(5)	Total	4,696,670,897	$0
(6)	Inclusion as Adjustment to FY 2023 O&M Reconciliation Balance		$69,828
(7)	Ending Over/(Under) Recovery		$0

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

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

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

Monthly kWh	Rates Effective July 1, 2023				Proposed Rates Effective October 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(a)	(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (k) / (e)	(p) = (l) / (e)	(q) = (m) / (e)	(r)
150	$33.21	$15.51	$2.03	$50.75	$33.14	$15.51	$2.03	$50.68	($0.07)	$0.00	$0.00	($0.07)	-0.1%	0.0%	0.0%	-0.1%	30.1%
300	$52.04	$31.02	$3.46	$86.52	$51.91	$31.02	$3.46	$86.39	($0.13)	$0.00	$0.00	($0.13)	-0.2%	0.0%	0.0%	-0.2%	12.9%
400	$64.60	$41.36	$4.42	$110.38	$64.43	$41.36	$4.41	$110.20	($0.17)	$0.00	($0.01)	($0.18)	-0.2%	0.0%	0.0%	-0.2%	11.6%
500	$77.16	$51.71	$5.37	$134.24	$76.94	$51.71	$5.36	$134.01	($0.22)	$0.00	($0.01)	($0.23)	-0.2%	0.0%	0.0%	-0.2%	9.6%
600	$89.71	$62.05	$6.32	$158.08	$89.45	$62.05	$6.31	$157.81	($0.26)	$0.00	($0.01)	($0.27)	-0.2%	0.0%	0.0%	-0.2%	7.7%
700	$102.27	$72.39	$7.28	$181.94	$101.97	$72.39	$7.27	$181.63	($0.30)	$0.00	($0.01)	($0.31)	-0.2%	0.0%	0.0%	-0.2%	19.0%
1,200	$165.05	$124.09	$12.05	$301.19	$164.54	$124.09	$12.03	$300.66	($0.51)	$0.00	($0.02)	($0.53)	-0.2%	0.0%	0.0%	-0.2%	6.8%
2,000	$265.51	$206.82	$19.68	$492.01	$264.65	$206.82	$19.64	$491.11	($0.86)	$0.00	($0.04)	($0.90)	-0.2%	0.0%	0.0%	-0.2%	2.3%

			Rates Effective July 1, 2023 (s)	Proposed Rates Effective October 1, 2023 (t)	Line Item on Bill
(1)	Distribution Customer Charge		$12.00	$12.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$1.58	$1.58	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge		$0.00245	$0.00245	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00000	$0.00016	
(7)	CapEx Factor Charge		$0.00710	$0.00710	
(8)	CapEx Reconciliation Factor		($0.00089)	($0.00148)	
(9)	Revenue Decoupling Adjustment Factor		$0.00076	$0.00076	
(10)	Pension Adjustment Factor		($0.00045)	($0.00045)	
(11)	Storm Fund Replenishment Factor		$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor		$0.00005	$0.00005	
(13)	Performance Incentive Factor		$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor		$0.00262	$0.00262	
(15)	LRS Adjustment Factor (Rates Effective April 1, 2023)		$0.00388	$0.00388	
(16)	Long-term Contracting for Renewable Energy Charge		$0.00660	$0.00660	Renewable Energy Distribution Charge
(17)	Net Metering Charge		$0.00628	$0.00628	
(18)	Base Transmission Charge		$0.03115	$0.03115	Transmission Charge
(19)	Transmission Adjustment Factor		$0.00183	$0.00183	
(20)	Transmission Uncollectible Factor		$0.00044	$0.00044	
(21)	Base Transition Charge		$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment		$0.00021	$0.00021	
(23)	Energy Efficiency Program Charge		$0.00986	$0.00986	Energy Efficiency Programs
(24)	Last Resort Service Base Charge		$0.09125	$0.09125	Supply Services Energy Charge
(25)	LRS Adjustment Factor		$0.00000	$0.00000	
(26)	LRS Adminstrative Cost Adjustment Factor		$0.00383	$0.00383	
(27)	Renewable Energy Standard Charge		$0.00833	$0.00833	
	Line Item on Bill				
(28)	Customer Charge		$12.00	$12.00	
(29)	LIHEAP Enhancement Charge		$0.79	$0.79	
(30)	RE Growth Program		$1.58	$1.58	
(31)	Transmission Charge	kWh x	$0.03342	$0.03342	
(32)	Distribution Energy Charge	kWh x	$0.06920	$0.06877	
(33)	Transition Charge	kWh x	$0.00021	$0.00021	
(34)	Energy Efficiency Programs	kWh x	$0.00986	$0.00986	
(35)	Renewable Energy Distribution Charge	kWh x	$0.01288	$0.01288	
(36)	Supply Services Energy Charge	kWh x	$0.10341	$0.10341	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023

Column (t): Line (6) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

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, 2023						Proposed Rates Effective October 1, 2023						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Percentage of Customers
(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	$32.81	$15.51	($12.08)	$36.24	$1.51	$37.75	$32.75	$15.51	($12.07)	$36.19	$1.51	$37.70	($0.05)	$0.00	$0.00	($0.05)	-0.1%	0.0%	0.0%	-0.1%	32.1%
300	$51.26	$31.02	($20.57)	$61.71	$2.57	$64.28	$51.13	$31.02	($20.54)	$61.61	$2.57	$64.18	($0.10)	$0.00	$0.00	($0.10)	-0.2%	0.0%	0.0%	-0.2%	15.4%
400	$63.55	$41.36	($26.23)	$78.68	$3.28	$81.96	$63.38	$41.36	($26.19)	$78.55	$3.27	$81.82	($0.13)	$0.00	($0.01)	($0.14)	-0.2%	0.0%	0.0%	-0.2%	12.5%
500	$75.85	$51.71	($31.89)	$95.67	$3.99	$99.66	$75.63	$51.71	($31.84)	$95.50	$3.98	$99.48	($0.17)	$0.00	($0.01)	($0.18)	-0.2%	0.0%	0.0%	-0.2%	9.6%
600	$88.14	$62.05	($37.55)	$112.64	$4.69	$117.33	$87.88	$62.05	($37.48)	$112.45	$4.69	$117.14	($0.19)	$0.00	$0.00	($0.19)	-0.2%	0.0%	0.0%	-0.2%	7.2%
700	$100.44	$72.39	($43.21)	$129.62	$5.40	$135.02	$100.13	$72.39	($43.13)	$129.39	$5.39	$134.78	($0.23)	$0.00	($0.01)	($0.24)	-0.2%	0.0%	0.0%	-0.2%	16.4%
1,200	$161.91	$124.09	($71.50)	$214.50	$8.94	$223.44	$161.39	$124.09	($71.37)	$214.11	$8.92	$223.03	($0.39)	$0.00	($0.02)	($0.41)	-0.2%	0.0%	0.0%	-0.2%	5.2%
2,000	$260.27	$206.82	($116.77)	$350.32	$14.60	$364.92	$259.41	$206.82	($116.56)	$349.67	$14.57	$364.24	($0.65)	$0.00	($0.03)	($0.68)	-0.2%	0.0%	0.0%	-0.2%	1.6%

	Rates Effective July 1, 2023 (w)	Proposed Rates Effective October 1, 2023 (x)	Line Item on Bill
(1) Distribution Customer Charge	$12.00	$12.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$1.58	$1.58	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	
(5) Operating & Maintenance Expense Charge	$0.00245	$0.00245	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00016	
(7) CapEx Factor Charge	$0.00710	$0.00710	
(8) CapEx Reconciliation Factor	($0.00089)	($0.00148)	
(9) Revenue Decoupling Adjustment Factor	$0.00076	$0.00076	Distribution Energy Charge
(10) Pension Adjustment Factor	($0.00045)	($0.00045)	
(11) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12) Arrearage Management Adjustment Factor	$0.00005	$0.00005	
(13) Performance Incentive Factor	$0.00000	$0.00000	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00388	$0.00388	
(16) Long-term Contracting for Renewable Energy Charge	$0.00660	$0.00660	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00628	$0.00628	
(18) Base Transmission Charge	$0.03115	$0.03115	
(19) Transmission Adjustment Factor	$0.00183	$0.00183	Transmission Charge
(20) Transmission Uncollectible Factor	$0.00044	$0.00044	
(21) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22) Transition Adjustment	$0.00021	$0.00021	
(23) Energy Efficiency Program Charge	$0.00986	$0.00986	Energy Efficiency Programs
(24) Last Resort Service Base Charge	$0.09125	$0.09125	
(25) LRS Adjustment Factor	$0.00000	$0.00000	Supply Services Energy Charge
(26) LRS Adminstrative Cost Adjustment Factor	$0.00383	$0.00383	
(27) Renewable Energy Standard Charge	$0.00833	$0.00833	
Line Item on Bill			
(28) Customer Charge	$12.00	$12.00	
(29) LIHEAP Enhancement Charge	$0.79	$0.79	
(30) RE Growth Program	$1.58	$1.58	
(31) Transmission Charge	$0.03342	$0.03342	
(32) Distribution Energy Charge	$0.06658	$0.06615	
(33) Transition Charge	$0.00021	$0.00021	
(34) Energy Efficiency Programs	$0.00986	$0.00986	
(35) Renewable Energy Distribution Charge	$0.01288	$0.01288	
(36) Supply Services Energy Charge	$0.10341	$0.10341	
(37) Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023
Column (x): Line (6) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

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, 2023						Proposed Rates Effective October 1, 2023						$ 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-.30	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$32.81	$15.51	($14.50)	$33.82	$1.41	$35.23	$32.75	$15.51	($14.48)	$33.78	$1.41	$35.19	($0.04)	$0.00	$0.00	($0.04)	-0.1%	0.0%	0.0%	-0.1%	32.1%
300	$51.26	$31.02	($24.68)	$57.60	$2.40	$60.00	$51.13	$31.02	($24.65)	$57.50	$2.40	$59.90	($0.10)	$0.00	$0.00	($0.10)	-0.2%	0.0%	0.0%	-0.2%	15.4%
400	$63.55	$41.36	($31.47)	$73.44	$3.06	$76.50	$63.38	$41.36	($31.42)	$73.32	$3.06	$76.38	($0.12)	$0.00	$0.00	($0.12)	-0.2%	0.0%	0.0%	-0.2%	12.5%
500	$75.85	$51.71	($38.27)	$89.29	$3.72	$93.01	$75.63	$51.71	($38.20)	$89.14	$3.71	$92.85	($0.15)	$0.00	($0.01)	($0.16)	-0.2%	0.0%	0.0%	-0.2%	9.6%
600	$88.14	$62.05	($45.06)	$105.13	$4.38	$109.51	$87.88	$62.05	($44.98)	$104.95	$4.37	$109.32	($0.18)	$0.00	($0.01)	($0.19)	-0.2%	0.0%	0.0%	-0.2%	7.2%
700	$100.44	$72.39	($51.85)	$120.98	$5.04	$126.02	$100.13	$72.39	($51.76)	$120.76	$5.03	$125.79	($0.22)	$0.00	($0.01)	($0.23)	-0.2%	0.0%	0.0%	-0.2%	16.4%
1,200	$161.91	$124.09	($85.80)	$200.20	$8.34	$208.54	$161.39	$124.09	($85.64)	$199.84	$8.33	$208.17	($0.36)	$0.00	($0.01)	($0.37)	-0.2%	0.0%	0.0%	-0.2%	5.2%
2,000	$260.27	$206.82	($140.13)	$326.96	$13.62	$340.58	$259.41	$206.82	($139.87)	$326.36	$13.60	$339.96	($0.60)	$0.00	($0.02)	($0.62)	-0.2%	0.0%	0.0%	-0.2%	1.6%

	Rates Effective July 1, 2023 (w)	Proposed Rates Effective October 1, 2023 (x)	Line Item on Bill
(1) Distribution Customer Charge	$12.00	$12.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$1.58	$1.58	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00245	$0.00245	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00016	
(7) CapEx Factor Charge	$0.00710	$0.00710	
(8) CapEx Reconciliation Factor	($0.00089)	($0.00148)	
(9) Revenue Decoupling Adjustment Factor	$0.00076	$0.00076	
(10) Pension Adjustment Factor	($0.00045)	($0.00045)	
(11) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12) Arrearage Management Adjustment Factor	$0.00005	$0.00005	
(13) Performance Incentive Factor	$0.00000	$0.00000	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00388	$0.00388	
(16) Long-term Contracting for Renewable Energy Charge	$0.00660	$0.00660	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00628	$0.00628	
(18) Base Transmission Charge	$0.03115	$0.03115	Transmission Charge
(19) Transmission Adjustment Factor	$0.00183	$0.00183	
(20) Transmission Uncollectible Factor	$0.00044	$0.00044	
(21) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22) Transition Adjustment	$0.00021	$0.00021	
(23) Energy Efficiency Program Charge	$0.00986	$0.00986	Energy Efficiency Programs
(24) Last Resort Service Base Charge	$0.09125	$0.09125	Supply Services Energy Charge
(25) LRS Adjustment Factor	$0.00000	$0.00000	
(26) LRS Adminstrative Cost Adjustment Factor	$0.00383	$0.00383	
(27) Renewable Energy Standard Charge	$0.00833	$0.00833	
Line Item on Bill			
(28) Customer Charge	$12.00	$12.00	
(29) LIHEAP Enhancement Charge	$0.79	$0.79	
(30) RE Growth Program	$1.58	$1.58	
(31) Transmission Charge	$0.03342	$0.03342	
(32) Distribution Energy Charge	$0.06658	$0.06615	
(33) Transition Charge	$0.00021	$0.00021	
(34) Energy Efficiency Programs	$0.00986	$0.00986	
(35) Renewable Energy Distribution Charge	$0.01288	$0.01288	
(36) Supply Services Energy Charge	$0.10341	$0.10341	
(37) Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023

Column (x): Line (6) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

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, 2023				Proposed Rates Effective October 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh (a)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)	of Customers (r)
250	$52.53	$24.99	$3.23	$80.75	$52.43	$24.99	$3.23	$80.65	($0.10)	$0.00	$0.00	($0.10)	-0.1%	0.0%	0.0%	-0.1%	56.3%
500	$81.83	$49.99	$5.49	$137.31	$81.64	$49.99	$5.48	$137.11	($0.19)	$0.00	($0.01)	($0.20)	-0.1%	0.0%	0.0%	-0.1%	16.9%
1,000	$140.42	$99.97	$10.02	$250.41	$140.04	$99.97	$10.00	$250.01	($0.38)	$0.00	($0.02)	($0.40)	-0.2%	0.0%	0.0%	-0.2%	8.1%
1,500	$199.02	$149.96	$14.54	$363.52	$198.45	$149.96	$14.52	$362.93	($0.57)	$0.00	($0.02)	($0.59)	-0.2%	0.0%	0.0%	-0.2%	5.0%
2,000	$257.61	$199.94	$19.06	$476.61	$256.85	$199.94	$19.03	$475.82	($0.76)	$0.00	($0.03)	($0.79)	-0.2%	0.0%	0.0%	-0.2%	13.6%

		Rates Effective July 1, 2023 (s)	Proposed Rates Effective October 1, 2023 (t)	Line Item on Bill
(1)	Distribution Customer Charge	$20.00	$20.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.44	$2.44	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04482	$0.04482	
(5)	Operating & Maintenance Expense Charge	$0.00239	$0.00239	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00016	
(7)	CapEx Factor Charge	$0.00589	$0.00589	
(8)	CapEx Reconciliation Factor	($0.00007)	($0.00061)	
(9)	Revenue Decoupling Adjustment Factor	$0.00076	$0.00076	Distribution Energy Charge
(10)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00005	$0.00005	
(13)	Performance Incentive Factor	$0.00000	$0.00000	
(14)	Low Income Discount Recovery Factor	$0.00262	$0.00262	
(15)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00265	$0.00265	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00660	$0.00660	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00628	$0.00628	
(18)	Base Transmission Charge	$0.03129	$0.03129	
(19)	Transmission Adjustment Factor	($0.00388)	($0.00388)	Transmission Charge
(20)	Transmission Uncollectible Factor	$0.00029	$0.00029	
(21)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(22)	Transition Adjustment	$0.00021	$0.00021	
(23)	Energy Efficiency Program Charge	$0.00986	$0.00986	Energy Efficiency Programs
(24)	Last Resort Service Base Charge	$0.08789	$0.08789	
(25)	LRS Adjustment Factor	$0.00000	$0.00000	Supply Services Energy Charge
(26)	LRS Adminstrative Cost Adjustment Factor	$0.00375	$0.00375	
(27)	Renewable Energy Standard Charge	$0.00833	$0.00833	
	Line Item on Bill			
(28)	Customer Charge	$20.00	$20.00	
(29)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$2.44	$2.44	
(31)	Transmission Charge	$0.02770	$0.02770	
(32)	Distribution Energy Charge	$0.06654	$0.06616	
(33)	Transition Charge	$0.00021	$0.00021	
(34)	Energy Efficiency Programs	$0.00986	$0.00986	
(35)	Renewable Energy Distribution Charge	$0.01288	$0.01288	
(36)	Supply Services Energy Charge	$0.09997	$0.09997	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023

Column (t): Line (6) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

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, 2023				Proposed Rates Effective October 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)
20	200	4,000	$546.06	$399.88	$39.41	$985.35	$544.06	$399.88	$39.33	$983.27	($2.00)	$0.00	($0.08)	($2.08)	-0.2%	0.0%	0.0%	-0.2%
50	200	10,000	$1,242.12	$999.70	$93.41	$2,335.23	$1,237.12	$999.70	$93.20	$2,330.02	($5.00)	$0.00	($0.21)	($5.21)	-0.2%	0.0%	0.0%	-0.2%
100	200	20,000	$2,402.22	$1,999.40	$183.40	$4,585.02	$2,392.22	$1,999.40	$182.98	$4,574.60	($10.00)	$0.00	($0.42)	($10.42)	-0.2%	0.0%	0.0%	-0.2%
150	200	30,000	$3,562.32	$2,999.10	$273.39	$6,834.81	$3,547.32	$2,999.10	$272.77	$6,819.19	($15.00)	$0.00	($0.62)	($15.62)	-0.2%	0.0%	0.0%	-0.2%
20	300	6,000	$640.28	$599.82	$51.67	$1,291.77	$637.28	$599.82	$51.55	$1,288.65	($3.00)	$0.00	($0.12)	($3.12)	-0.2%	0.0%	0.0%	-0.2%
50	300	15,000	$1,477.67	$1,499.55	$124.05	$3,101.27	$1,470.17	$1,499.55	$123.74	$3,093.46	($7.50)	$0.00	($0.31)	($7.81)	-0.2%	0.0%	0.0%	-0.3%
100	300	30,000	$2,873.32	$2,999.10	$244.68	$6,117.10	$2,858.32	$2,999.10	$244.06	$6,101.48	($15.00)	$0.00	($0.62)	($15.62)	-0.2%	0.0%	0.0%	-0.3%
150	300	45,000	$4,268.97	$4,498.65	$365.32	$9,132.94	$4,246.47	$4,498.65	$364.38	$9,109.50	($22.50)	$0.00	($0.94)	($23.44)	-0.2%	0.0%	0.0%	-0.3%
20	400	8,000	$734.50	$799.76	$63.93	$1,598.19	$730.50	$799.76	$63.76	$1,594.02	($4.00)	$0.00	($0.17)	($4.17)	-0.3%	0.0%	0.0%	-0.3%
50	400	20,000	$1,713.22	$1,999.40	$154.69	$3,867.31	$1,703.22	$1,999.40	$154.28	$3,856.90	($10.00)	$0.00	($0.41)	($10.41)	-0.3%	0.0%	0.0%	-0.3%
100	400	40,000	$3,344.42	$3,998.80	$305.97	$7,649.19	$3,324.42	$3,998.80	$305.13	$7,628.35	($20.00)	$0.00	($0.84)	($20.84)	-0.3%	0.0%	0.0%	-0.3%
150	400	60,000	$4,975.62	$5,998.20	$457.24	$11,431.06	$4,945.62	$5,998.20	$455.99	$11,399.81	($30.00)	$0.00	($1.25)	($31.25)	-0.3%	0.0%	0.0%	-0.3%
20	500	10,000	$828.72	$999.70	$76.18	$1,904.60	$823.72	$999.70	$75.98	$1,899.40	($5.00)	$0.00	($0.20)	($5.20)	-0.3%	0.0%	0.0%	-0.3%
50	500	25,000	$1,948.77	$2,499.25	$185.33	$4,633.35	$1,936.27	$2,499.25	$184.81	$4,620.33	($12.50)	$0.00	($0.52)	($13.02)	-0.3%	0.0%	0.0%	-0.3%
100	500	50,000	$3,815.52	$4,998.50	$367.25	$9,181.27	$3,790.52	$4,998.50	$366.21	$9,155.23	($25.00)	$0.00	($1.04)	($26.04)	-0.3%	0.0%	0.0%	-0.3%
150	500	75,000	$5,682.27	$7,497.75	$549.17	$13,729.19	$5,644.77	$7,497.75	$547.61	$13,690.13	($37.50)	$0.00	($1.56)	($39.06)	-0.3%	0.0%	0.0%	-0.3%
20	600	12,000	$922.94	$1,199.64	$88.44	$2,211.02	$916.94	$1,199.64	$88.19	$2,204.77	($6.00)	$0.00	($0.25)	($6.25)	-0.3%	0.0%	0.0%	-0.3%
50	600	30,000	$2,184.32	$2,999.10	$215.98	$5,399.40	$2,169.32	$2,999.10	$215.35	$5,383.77	($15.00)	$0.00	($0.63)	($15.63)	-0.3%	0.0%	0.0%	-0.3%
100	600	60,000	$4,286.62	$5,998.20	$428.53	$10,713.35	$4,256.62	$5,998.20	$427.28	$10,682.10	($30.00)	$0.00	($1.25)	($31.25)	-0.3%	0.0%	0.0%	-0.3%
150	600	90,000	$6,388.92	$8,997.30	$641.09	$16,027.31	$6,343.92	$8,997.30	$639.22	$15,980.44	($45.00)	$0.00	($1.87)	($46.87)	-0.3%	0.0%	0.0%	-0.3%

		Rates Effective July 1, 2023 (r)	Proposed Rates Effective October 1, 2023 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$24.33	$24.33	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 10kW)	$6.90	$6.90	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 10kW)	$1.91	$1.91	
(6)	Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00215	$0.00215	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00016	
(9)	CapEx Reconciliation Factor	($0.00072)	($0.00138)	
(10)	Revenue Decoupling Adjustment Factor	$0.00076	$0.00076	
(11)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00005	$0.00005	
(14)	Performance Incentive Factor	$0.00000	$0.00000	
(15)	Low Income Discount Recovery Factor	$0.00262	$0.00262	
(16)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00265	$0.00265	
(17)	Long-term Contracting for Renewable Energy Charge	$0.00660	$0.00660	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.00628	$0.00628	
(19)	Transmission Demand Charge	$4.97	$4.97	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01011	$0.01011	Transmission Adjustment
(21)	Transmission Adjustment Factor	($0.00594)	($0.00594)	
(22)	Transmission Uncollectible Factor	$0.00029	$0.00029	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00021	$0.00021	
(25)	Energy Efficiency Program Charge	$0.00986	$0.00986	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.08789	$0.08789	Supply Services Energy Charge
(27)	LRS Adjustment Factor	$0.00000	$0.00000	
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00375	$0.00375	
(29)	Renewable Energy Standard Charge	$0.00833	$0.00833	
	Line Item on Bill			
(30)	Customer Charge	$145.00	$145.00	
(32)	LIHEAP Enhancement Charge	$0.79	$0.79	
(31)	RE Growth Program	$24.33	$24.33	
(33)	Transmission Adjustment	$0.00446	$0.00446	
(34)	Distribution Energy Charge	$0.01970	$0.01920	
(35)	Distribution Demand Charge	$8.81	$8.81	
(36)	Transmission Demand Charge	$4.97	$4.97	
(35)	Transition Charge	$0.00021	$0.00021	
(36)	Energy Efficiency Programs	$0.00986	$0.00986	
(37)	Renewable Energy Distribution Charge	$0.01288	$0.01288	
(38)	Supply Services Energy Charge	$0.09997	$0.09997	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023

Column (s): Line (8) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

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, 2023				Proposed Rates Effective October 1, 2023				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use	kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total
	(a)		(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (k) / (e)	(p) = (l) / (e)	(q) = (m) / (e)
200	200	40,000	$4,298.35	$4,613.87	$371.34	$9,283.56	$4,288.75	$4,613.87	$370.94	$9,273.56	($9.60)	$0.00	($0.40)	($10.00)	-0.1%	0.0%	0.0%	-0.1%
750	200	150,000	$16,496.25	$17,302.00	$1,408.26	$35,206.51	$16,460.25	$17,302.00	$1,406.76	$35,169.01	($36.00)	$0.00	($1.50)	($37.50)	-0.1%	0.0%	0.0%	-0.1%
1,000	200	200,000	$22,040.75	$23,069.33	$1,879.59	$46,989.67	$21,992.75	$23,069.33	$1,877.59	$46,939.67	($48.00)	$0.00	($2.00)	($50.00)	-0.1%	0.0%	0.0%	-0.1%
1,500	200	300,000	$33,129.75	$34,604.00	$2,822.24	$70,555.99	$33,057.75	$34,604.00	$2,819.24	$70,480.99	($72.00)	$0.00	($3.00)	($75.00)	-0.1%	0.0%	0.0%	-0.1%
2,500	200	500,000	$55,307.75	$57,673.33	$4,707.55	$117,688.63	$55,187.75	$57,673.33	$4,702.55	$117,563.63	($120.00)	$0.00	($5.00)	($125.00)	-0.1%	0.0%	0.0%	-0.1%
5,000	200	1,000,000	$110,752.75	$115,346.67	$9,420.81	$235,520.23	$110,512.75	$115,346.67	$9,410.81	$235,270.23	($240.00)	$0.00	($10.00)	($250.00)	-0.1%	0.0%	0.0%	-0.1%
7,500	200	1,500,000	$166,197.75	$173,020.00	$14,134.07	$353,351.82	$165,837.75	$173,020.00	$14,119.07	$352,976.82	($360.00)	$0.00	($15.00)	($375.00)	-0.1%	0.0%	0.0%	-0.1%
10,000	200	2,000,000	$221,642.75	$230,693.33	$18,847.34	$471,183.42	$221,162.75	$230,693.33	$18,827.34	$470,683.42	($480.00)	$0.00	($20.00)	($500.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	200	4,000,000	$443,422.75	$461,386.67	$37,700.40	$942,509.82	$442,462.75	$461,386.67	$37,660.40	$941,509.82	($960.00)	$0.00	($40.00)	($1,000.00)	-0.1%	0.0%	0.0%	-0.1%
200	300	60,000	$5,291.15	$6,920.80	$508.83	$12,720.78	$5,276.75	$6,920.80	$508.23	$12,705.78	($14.40)	$0.00	($0.60)	($15.00)	-0.1%	0.0%	0.0%	-0.1%
750	300	225,000	$20,219.25	$25,953.00	$1,923.84	$48,096.09	$20,165.25	$25,953.00	$1,921.59	$48,039.84	($54.00)	$0.00	($2.25)	($56.25)	-0.1%	0.0%	0.0%	-0.1%
1,000	300	300,000	$27,004.75	$34,604.00	$2,567.03	$64,175.78	$26,932.75	$34,604.00	$2,564.03	$64,100.78	($72.00)	$0.00	($3.00)	($75.00)	-0.1%	0.0%	0.0%	-0.1%
1,500	300	450,000	$40,575.75	$51,906.00	$3,853.41	$96,335.16	$40,467.75	$51,906.00	$3,848.91	$96,222.66	($108.00)	$0.00	($4.50)	($112.50)	-0.1%	0.0%	0.0%	-0.1%
2,500	300	750,000	$67,717.75	$86,510.00	$6,426.16	$160,653.91	$67,537.75	$86,510.00	$6,418.66	$160,466.41	($180.00)	$0.00	($7.50)	($187.50)	-0.1%	0.0%	0.0%	-0.1%
5,000	300	1,500,000	$135,572.75	$173,020.00	$12,858.03	$321,450.78	$135,212.75	$173,020.00	$12,843.03	$321,075.78	($360.00)	$0.00	($15.00)	($375.00)	-0.1%	0.0%	0.0%	-0.1%
7,500	300	2,250,000	$203,427.75	$259,530.00	$19,289.91	$482,247.66	$202,887.75	$259,530.00	$19,267.41	$481,685.16	($540.00)	$0.00	($22.50)	($562.50)	-0.1%	0.0%	0.0%	-0.1%
10,000	300	3,000,000	$271,282.75	$346,040.00	$25,721.78	$643,044.53	$270,562.75	$346,040.00	$25,691.78	$642,294.53	($720.00)	$0.00	($30.00)	($750.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	300	6,000,000	$542,702.75	$692,080.00	$51,449.29	$1,286,232.04	$541,262.75	$692,080.00	$51,389.29	$1,284,732.04	($1,440.00)	$0.00	($60.00)	($1,500.00)	-0.1%	0.0%	0.0%	-0.1%
200	400	80,000	$6,283.95	$9,227.73	$646.32	$16,158.00	$6,264.75	$9,227.73	$645.52	$16,138.00	($19.20)	$0.00	($0.80)	($20.00)	-0.1%	0.0%	0.0%	-0.1%
750	400	300,000	$23,942.25	$34,604.00	$2,439.43	$60,985.68	$23,870.25	$34,604.00	$2,436.43	$60,910.68	($72.00)	$0.00	($3.00)	($75.00)	-0.1%	0.0%	0.0%	-0.1%
1,000	400	400,000	$31,968.75	$46,138.67	$3,254.48	$81,361.90	$31,872.75	$46,138.67	$3,250.48	$81,261.90	($96.00)	$0.00	($4.00)	($100.00)	-0.1%	0.0%	0.0%	-0.1%
1,500	400	600,000	$48,021.75	$69,208.00	$4,884.57	$122,114.32	$47,877.75	$69,208.00	$4,878.57	$121,964.32	($144.00)	$0.00	($6.00)	($150.00)	-0.1%	0.0%	0.0%	-0.1%
2,500	400	1,000,000	$80,127.75	$115,346.67	$8,144.77	$203,619.19	$79,887.75	$115,346.67	$8,134.77	$203,369.19	($240.00)	$0.00	($10.00)	($250.00)	-0.1%	0.0%	0.0%	-0.1%
5,000	400	2,000,000	$160,392.75	$230,693.33	$16,295.25	$407,381.33	$159,912.75	$230,693.33	$16,275.25	$406,881.33	($480.00)	$0.00	($20.00)	($500.00)	-0.1%	0.0%	0.0%	-0.1%
7,500	400	3,000,000	$240,657.75	$346,040.00	$24,445.74	$611,143.49	$239,937.75	$346,040.00	$24,415.74	$610,393.49	($720.00)	$0.00	($30.00)	($750.00)	-0.1%	0.0%	0.0%	-0.1%
10,000	400	4,000,000	$320,922.75	$461,386.67	$32,596.23	$814,905.65	$319,962.75	$461,386.67	$32,556.23	$813,905.65	($960.00)	$0.00	($40.00)	($1,000.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	400	8,000,000	$641,982.75	$922,773.33	$65,198.18	$1,629,954.26	$640,062.75	$922,773.33	$65,118.18	$1,627,954.26	($1,920.00)	$0.00	($80.00)	($2,000.00)	-0.1%	0.0%	0.0%	-0.1%
200	500	100,000	$7,276.75	$11,534.67	$783.81	$19,595.23	$7,252.75	$11,534.67	$782.81	$19,570.23	($24.00)	$0.00	($1.00)	($25.00)	-0.1%	0.0%	0.0%	-0.1%
750	500	375,000	$27,665.25	$43,255.00	$2,955.01	$73,875.26	$27,575.25	$43,255.00	$2,951.26	$73,781.51	($90.00)	$0.00	($3.75)	($93.75)	-0.1%	0.0%	0.0%	-0.1%
1,000	500	500,000	$36,932.75	$57,673.33	$3,941.92	$98,548.00	$36,812.75	$57,673.33	$3,936.92	$98,423.00	($120.00)	$0.00	($5.00)	($125.00)	-0.1%	0.0%	0.0%	-0.1%
1,500	500	750,000	$55,467.75	$86,510.00	$5,915.74	$147,893.49	$55,287.75	$86,510.00	$5,908.24	$147,705.99	($180.00)	$0.00	($7.50)	($187.50)	-0.1%	0.0%	0.0%	-0.1%
2,500	500	1,250,000	$92,537.75	$144,183.33	$9,863.38	$246,584.46	$92,237.75	$144,183.33	$9,850.88	$246,271.96	($300.00)	$0.00	($12.50)	($312.50)	-0.1%	0.0%	0.0%	-0.1%
5,000	500	2,500,000	$185,212.75	$288,366.67	$19,732.48	$493,311.90	$184,612.75	$288,366.67	$19,707.48	$492,686.90	($600.00)	$0.00	($25.00)	($625.00)	-0.1%	0.0%	0.0%	-0.1%
7,500	500	3,750,000	$277,887.75	$432,550.00	$29,601.58	$740,039.33	$276,987.75	$432,550.00	$29,564.08	$739,101.83	($900.00)	$0.00	($37.50)	($937.50)	-0.1%	0.0%	0.0%	-0.1%
10,000	500	5,000,000	$370,562.75	$576,733.33	$39,470.67	$986,766.75	$369,362.75	$576,733.33	$39,420.67	$985,516.75	($1,200.00)	$0.00	($50.00)	($1,250.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	500	10,000,000	$741,262.75	$1,153,466.67	$78,947.07	$1,973,676.49	$738,862.75	$1,153,466.67	$78,847.07	$1,971,176.49	($2,400.00)	$0.00	($100.00)	($2,500.00)	-0.1%	0.0%	0.0%	-0.1%
200	600	120,000	$8,269.55	$13,841.60	$921.30	$23,032.45	$8,240.75	$13,841.60	$920.10	$23,002.45	($28.80)	$0.00	($1.20)	($30.00)	-0.1%	0.0%	0.0%	-0.1%
750	600	450,000	$31,388.25	$51,906.00	$3,470.59	$86,764.84	$31,280.25	$51,906.00	$3,466.09	$86,652.34	($108.00)	$0.00	($4.50)	($112.50)	-0.1%	0.0%	0.0%	-0.1%
1,000	600	600,000	$41,896.75	$69,208.00	$4,629.36	$115,734.11	$41,752.75	$69,208.00	$4,623.36	$115,584.11	($144.00)	$0.00	($6.00)	($150.00)	-0.1%	0.0%	0.0%	-0.1%
1,500	600	900,000	$62,913.75	$103,812.00	$6,946.91	$173,672.66	$62,697.75	$103,812.00	$6,937.91	$173,447.66	($216.00)	$0.00	($9.00)	($225.00)	-0.1%	0.0%	0.0%	-0.1%
2,500	600	1,500,000	$104,947.75	$173,020.00	$11,581.99	$289,549.74	$104,587.75	$173,020.00	$11,566.99	$289,174.74	($360.00)	$0.00	($15.00)	($375.00)	-0.1%	0.0%	0.0%	-0.1%
5,000	600	3,000,000	$210,032.75	$346,040.00	$23,169.70	$579,242.45	$209,312.75	$346,040.00	$23,139.70	$578,492.45	($720.00)	$0.00	($30.00)	($750.00)	-0.1%	0.0%	0.0%	-0.1%
7,500	600	4,500,000	$315,117.75	$519,060.00	$34,757.41	$868,935.16	$314,037.75	$519,060.00	$34,712.41	$867,810.16	($1,080.00)	$0.00	($45.00)	($1,125.00)	-0.1%	0.0%	0.0%	-0.1%
10,000	600	6,000,000	$420,202.75	$692,080.00	$46,345.12	$1,158,627.87	$418,762.75	$692,080.00	$46,285.12	$1,157,127.87	($1,440.00)	$0.00	($60.00)	($1,500.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	600	12,000,000	$840,542.75	$1,384,160.00	$92,695.96	$2,317,398.71	$837,662.75	$1,384,160.00	$92,575.96	$2,314,398.71	($2,880.00)	$0.00	($120.00)	($3,000.00)	-0.1%	0.0%	0.0%	-0.1%

		Rates Effective July 1, 2023	Proposed Rates Effective October 1, 2023	Line Item on Bill
		(r)	(s)	
(1)	Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$197.96	$197.96	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 200kW)	$5.30	$5.30	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 200kW)	$1.88	$1.88	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00108	$0.00108	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00000	$0.00016	
(9)	CapEx Reconciliation Factor	($0.00045)	($0.00085)	
(10)	Revenue Decoupling Adjustment Factor	$0.00076	$0.00076	
(11)	Pension Adjustment Factor	($0.00045)	($0.00045)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00005	$0.00005	
(14)	Performance Incentive Factor	$0.00000	$0.00000	
(15)	Low Income Discount Recovery Factor	$0.00262	$0.00262	
(16)	LRS Adjustment Factor (Rates Effective April 1, 2023)	$0.00057	$0.00057	
(17)	Long-term Contracting for Renewable Energy Charge	$0.00660	$0.00660	Renewable Energy Distribution Charge
(18)	Net Metering Charge	$0.00628	$0.00628	
(19)	Transmission Demand Charge	$5.07	$5.07	Transmission Demand Charge
(20)	Base Transmission Charge	$0.01124	$0.01124	Transmission Adjustment
(21)	Transmission Adjustment Factor	($0.00123)	($0.00123)	
(22)	Transmission Uncollectible Factor	$0.00032	$0.00032	
(23)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(24)	Transition Adjustment	$0.00021	$0.00021	
(25)	Energy Efficiency Program Charge	$0.00986	$0.00986	Energy Efficiency Programs
(26)	Last Resort Service Base Charge	$0.09922	$0.09922	Supply Services Energy Charge
(27)	LRS Adjustment Factor	$0.00000	$0.00000	
(28)	LRS Adminstrative Cost Adjustment Factor	$0.00780	$0.00780	
(29)	Renewable Energy Standard Charge	$0.00833	$0.00833	
	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	$197.96	$197.96	
(33)	Transmission Adjustment	$0.01033	$0.01033	
(34)	Distribution Energy Charge	$0.01636	$0.01612	
(35)	Distribution Demand Charge	$7.18	$7.18	
(36)	Transmission Demand Charge	$5.07	$5.07	
(35)	Transition Charge	$0.00021	$0.00021	
(36)	Energy Efficiency Programs	$0.00986	$0.00986	
(37)	Renewable Energy Distribution Charge	$0.01288	$0.01288	
(38)	Supply Services Energy Charge	$0.11535	$0.11535	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2023
Column (s): Line (8) per Attachment TGS-3, Page 1, Line (7). 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 7/1/2023, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096 effective 7/1/2023.

Attachment TGS-5

Correction of Fiscal Year 2022 CapEx Reconciliation Over/(Under) Recovery

Correction of Fiscal Year 2022 CapEx Reconciliation Over/(Under) Recovery

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Section I: Prior to April 1st, 2022 Proration - As-Filed: Docket No. 5098, Attachment PRB-2, Page 2 of 4							
		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**	**Total**
(1)	kWh - March 2022 (Incorrect)	237,585,313	60,919,900	103,690,927	189,940,474	5,429,953	1,413,298	598,979,865
(2)	kW - April 2022	-	-	282,036	474,010	-	-	756,046
(3)	CapEx Factor Charge Prior to April 1, 2022	$ 0.00544	$ 0.00456	$ 1.44	$ 1.39	$ 0.00688	$ 0.00059	
(4)	CapEx Reconciliation Factor Prior to April 1, 2022	$ (0.00069)	$ 0.00013	$ (0.00012)	$ (0.00013)	$ 0.00051	$ (0.00021)	
(5)	% of Consumption prior to April 1, 2022	58.25%	58.25%	58.25%	58.25%	58.25%	58.25%	
(6)	Total Revenue Prior to April 1, 2022	$ 657,317	$ 166,415	$ 229,305	$ 369,379	$ 23,372	$ 313	$ 1,446,101
(7)	CapEx Reconciliation Factor Revenue Prior to April 1, 2022	$ (95,484)	$ 4,613	$ (7,247)	$ (14,384)	$ 1,613	$ (173)	$ (111,063)
(8)	CapEx Factor Charge Revenue Prior to April 1, 2022	$ 752,800	$ 161,803	$ 236,553	$ 383,763	$ 21,759	$ 486	$ 1,557,164
	Section II: Prior to April 1st, 2022 Proration - Corrected							
		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**	**Total**
(9)	kWh - April 2022 (Correct)	219,302,240	58,598,144	99,132,350	182,235,879	3,534,580	1,489,697	564,292,890
(10)	kW - April 2022	-	-	282,036	474,010	-	-	756,046
(11)	CapEx Factor Charge Prior to April 1, 2022	$ 0.00544	$ 0.00456	$ 1.44	$ 1.39	$ 0.00688	$ 0.00059	
(12)	CapEx Reconciliation Factor Prior to April 1, 2022	$ (0.00069)	$ 0.00013	$ (0.00012)	$ (0.00013)	$ 0.00051	$ (0.00021)	
(13)	% of Consumption prior to April 1, 2022	58.25%	58.25%	58.25%	58.25%	58.25%	58.25%	
(14)	Total Revenue Prior to April 1, 2022	$ 606,734	$ 160,073	$ 229,624	$ 369,965	$ 15,214	$ 330	$ 1,381,939
(15)	CapEx Reconciliation Factor Revenue Prior to April 1, 2022	$ (88,136)	$ 4,437	$ (6,929)	$ (13,799)	$ 1,050	$ (182)	$ (103,559)
(16)	CapEx Factor Charge Revenue Prior to April 1, 2022	$ 694,870	$ 155,636	$ 236,553	$ 383,763	$ 14,164	$ 512	$ 1,485,498
(17)	**Difference in Base Rate Revenue - Corrected Vs. As-Filed**	**$ (57,931)**	**$ (6,167)**	**$ -**	**$ -**	**$ (7,595)**	**$ 26**	**$ (71,666)**

		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**	**Total**
(18)	Fiscal Year 2022 CapEx Reconciliation Over/(Under) Recovery (As-Filed)	$ 2,837,869	$ 48,957	$ 895,217	$ 1,011,808	$ (16,378)	$ 2,288	$ 4,779,760
(19)	Incremental Reduction to Over-Recovery due to Lower Corrected Pro-Rated April 2022 Revenue	$ 57,931	$ 6,167	$ -	$ -	$ 7,595	$ (26)	$ 71,666
(20)	Fiscal Year 2022 CapEx Reconciliation Over Recovery (Corrected)	**$ 2,779,938**	**$ 42,790**	**$ 895,217**	**$ 1,011,808**	**$ (23,974)**	**$ 2,314**	**$ 4,708,094**

Notes:

(1) Source: Internal Company Records
(2) Source: Internal Company Records
(3) R.I.P.U.C. Tariff No. 2095 Effective 2/1/2022
(4) R.I.P.U.C. Tariff No. 2095 Effective 2/1/2022
(5) Source: Internal Company Records
(6) = (7) + (8)
(7) = (1) x (4) x (5)
(8) For Columns (A), (B), (E), and (F), (8) = (1) x (3) x (5); for Columns (C) and (D), (8) = (2) x (3) x (5). Please note that for the 944,362 kWh associated with B-32, Line (8) was erroneously calculated using a "CapEx Reconciliation Factor" of ($0.000134) instead of ($0.00013). This has been corrected in Section II.
(9) Source: Internal Company Records
(10) = (2)
(11) = (3)
(12) = (4)
(13) = (5)
(14) = (15) + (16)
(15) = (9) x (12) x (13)
(16) For Columns (A), (B), (E), and (F), (16) = (9) x (11) x (13); for Columns (C) and (D), (16) = (10) x (11) x (13).
(17) = (16) - (8)
(18) Source: R.I.P.U.C. Docket No. 5098, Attachment PRB-2, Page 1 of 4, Line (8).
(19) = -(17)
(20) = (18) + (19)