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

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

Rhode Island Energy™
a PPL company

February 7, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-48-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 7 (Complete Set)

Dear Ms. Massaro:

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

This transmittal contains the Company's response to data request Division 7-6, which was the remaining response in this set.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-48-EL Service List

Division 7-1

Request:

Regarding response to DIV 2-3:

a. Identify the seven transformers with contingencies that do not have an adequate spare transformer. Identify any transformers that are also listed in the Company's response to 2-19a.

b. Of the seven transformers, identify those that can be supported by mobiles owned by RIE.

c. Of the seven transformers, identify those that would have been supported by mobiles under National Grid ownership.

d. The Company states that "The in-service transformers that these seven spare transformers provide coverage for did not have an adequate spare transformer at National Grid." Why was it acceptable that spares were not available under National Grid ownership but are required under PPL ownership?

Response:

Please see the responses on the subsequent pages.

Division 7-1, page 2

a. The seven transformers that were referenced in DIV 2-3 represent transformers that did not have a dedicated spare transformer prior to the acquisition of The Narragansett Electric Company by a subsidiary of PPL Corporation from National Grid USA ("National Grid") and do not currently have a spare in inventory. The table below outlines those seven transformers.

Voltage	Winding Configuration
115Y/66.4kV-34.5Y/19.92kV 33/44/55 MVA LTC	Wye-Wye-Delta
115-34.5-13.8 24/32/40 MVA	Wye-Wye-Delta
115-23kV 30/40/50	Delta-ZigZag
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta
23-11.5kV 10/12.5MVA	ZigZag-Delta

The following transformers correspond to the substations identified in DIV 2-19a and do not have an adequate spare in inventory.

Voltage	Winding Configuration
115-13.2kV 33/44/55 LTC	Delta-Wye
115-13.2 24/32/40 LTC	Delta-Wye
69-13.8kV 24/32/40 LTC	Delta-Wye
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye

Division 7-1, page 3

b. The table below identifies how many of the seven transformers listed in DIV 7-1a can be supported by mobiles currently in the Rhode Island Energy inventory.

Voltage	Winding Configuration	RIE Mobile Supported (Y/N)
115Y/66.4kV-34.5Y/19.92kV 33/44/55 MVA LTC	Wye-Wye-Delta	N
115-34.5-13.8 24/32/40 MVA	Wye-Wye-Delta	N
115-23kV 30/40/50	Delta-ZigZag	N
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	N
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	Y*
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	N
23-11.5kV 10/12.5MVA	ZigZag-Delta	N

* Rhode Island Energy has a mobile substation with matching voltage ratings, but the rated capacity does not match the capacity of the in-service transformer.

Division 7-1, page 4

c. Of the seven transformers identified in DIV 7-1a, the table below shows the transformers that would have been supported by mobiles under National Grid ownership.

Voltage	Winding Configuration	National Grid Mobile Supported (Y/N)
115Y/66.4kV-34.5Y/19.92kV 33/44/55 MVA LTC	Wye-Wye-Delta	Y
115-34.5-13.8 24/32/40 MVA	Wye-Wye-Delta	Y
115-23kV 30/40/50	Delta-ZigZag	Y*
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	Y*
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	Y**
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	N
23-11.5kV 10/12.5MVA	ZigZag-Delta	N

* National Grid had a mobile substation with adequate capacity, but the winding configuration did not match the winding configuration of the in-service transformer.

**National Grid had a mobile substation with matching voltage ratings, but the rated capacity did not match the capacity of the in-service transformer. That mobile substation is now owned by Rhode Island Energy.

Division 7-1, page 5

d. Under National Grid ownership, it was acceptable that spare transformers were not available for the seven transformers shown in DIV 7-1a because lead times were considerably shorter and National Grid maintained a larger fleet of mobile substations. Because lead times were shorter, the Company felt comfortable using a mobile substation, or a non-identical spare transformer, while a replacement transformer was being procured. The non-identical spare transformer represents spares that did not have the same capacity as the failed transformer, or winding configuration, and resulted in the system being in an abnormal configuration while the new transformer was being manufactured.

   Under PPL ownership, transformer lead times have increased from 32-44 weeks to 104-156 weeks, and the number of mobile substations has decreased. Leaving a mobile substation energized for 2-3 years while a new transformer is being procured limits the availability of the mobile for any subsequent failures at other substations. Similarly, if the Company uses a spare transformer of similar voltage ratings, but of lesser capacity, or with a different winding configuration, the system will be in an abnormal state for a prolonged period, and the spare would not be able to be installed elsewhere for a failure.

Division 7-2

Request:

For each transformer listed in response to DIV 2-8, provide the age and health of the transformer at the time of failure. Indicate transformers that were on a watch list or identified for replacement and the proposed replacement time frame.

Response:

Please see the table below summarizing the age and health at the time of failure for each transformer identified in the Company's response to DIV 2-8, along with information identifying whether the transformer was on a watch list or had been identified for replacement prior to failure.

Substation & Transformer	Age (Yrs)	Transformer health at the time of failure	Watch List (Y/N)	Identified for Replacement (Y/N)	Replacement Timeframe
Warwick Mall (T2)	45	• No known health issues.	N	N	N/A
Valley (22T)	55	• Transformer was leaking nitrogen, but no health issues of concern. • Transformer failure identified via a routine Dissolved gas analysis (DGA).	N	N	N/A
Hospital (T462)	50	• No known health issues.	N	N	N/A
Sockanosset (T1)	47	• This transformer had a load tap changer (LTC) that required above average maintenance. • The transformer had broken braids, leaks, was loud, and was retrofitted due to sludge buildup.	Y	Y	No proposed timeframe.
Westerly (T4)	44	• No known health issues.	N	N	N/A

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

Division 7-2, page 2

Substation & Transformer	Age (Yrs)	Transformer health at the time of failure	Watch List (Y/N)	Identified for Replacement (Y/N)	Replacement Timeframe
Westerly (T2)	47	• The T2 transformer had a DGA history spike in Methane & Ethylene when it was heavily loaded due to the T4 failure. • The transformer also leaked from the LTC tank into the main tank when pressure increased.	Y	N	N/A
Hopkins Hill (T2)	32	• No known health issues at the time of failure. • Transformer failure identified via a routine DGA.	N	N	N/A
Sprague St (T2)	72	• No known health issues. • In 2014, the T2 transformer was impacted by a fault on the high side of the transformer, causing a hole in the radiator. The radiator was repaired, and the transformer placed back in service.	N	N	N/A
Apponaug (T4)	51	• In the 2021 asset condition report, the T4 transformer was identified as needing to be replaced within 5-10 years.	N	Y	FY28-FY29

Division 7-3

Request:

Confirm that load cannot be served via feeder ties from adjacent stations for the 15 stations and associated transformers that do not have N-1 contingency capability during peak loading (listed in DIV 1-19a). What are the amounts and duration of unserved loads for each of the 15 transformers? Do any substations serve load in Massachusetts or have tie capability to transfer load to substations in Massachusetts? If so, how much load can be transferred and would the transfer resolve the N-1 contingency? Is the opportunity to transfer load to substations in Massachusetts the same or different under PPL ownership? Explain.

Response:

Please see the table on the subsequent page for additional information regarding the 15 substations from the Company's response to DIV 1-19a. The "Assumed Duration of Outage" column reflects the standard Company planning criteria philosophy that all repairs are completed, or mobile equipment is energized, within 24 hours after the initiating event. Without a mobile substation available, the Company would evaluate the increased loading on substation and line equipment, review the expected substation power transformer loss-of-life resulting from the increased loading and elevated temperature and decide on how to best restore the remaining customers within 24 hours.

Of the 18 transformers listed in the table, only two do not have additional area ties to assist in the event of a load-at-risk contingency. None of the substations listed in the table serves Massachusetts load or has tie capability to Massachusetts feeders or substations. The Company has the same opportunity to transfer load to substations in Massachusetts as a PPL affiliate as it did when it was owned by National Grid USA.

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

Division 7-3, page 2

Station	Transformer(s)	2023 MVA At Risk before Switching	2023 MVA of available switching	2023 MVA at Risk after Switching (Unserved Load)	Assumed Duration of Outage	Ties to MA Substation
Washington	T261 & T262	29.2 - T261 32.7 - T262	26.6 - T261 27.5 - T262	2.6 - T261 5.2 - T262	24 HRS	No
New London	T2	30	22.7	7.3	24 HRS	No
West Cranston	T2	19.9	19.1	0.8	24 HRS	No
Wampanoag	T1 & T2	29.7 - T1 29.1 - T2	26.2 - T1 23.1 - T2	3.4 - T1 6.1 - T2	24 HRS	No
Staples	T124	27.5	17	10.5	24 HRS	No
Valley	T22 & T23	23.7 - T22 2.7 - T23	19.2 - T22 0 - T23	4.5 - T22 2.7 - T23	24 HRS	No
Dexter	T364	26.5	18.3	8.2	24 HRS	No
Tower Hill	T1	35.5	26.4	9.1	24 HRS	No
Chase Hill	T2	29.1	10.7	18.4	24 HRS	No
Newport	T1	24.4	16.1	8.3	24 HRS	No
Tiverton	T2	17.8	15.9	1.9	24 HRS	No
Shun Pike	T1	15.7	0	15.7	24 HRS	No
Johnston	T3	53.1	46	7.1	24 HRS	No
Elmwood	T2	27.5	10.9	16.6	24 HRS	No

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

---

Division 7-4

Request:

Regarding response to DIV 2-19d, the Company states that "The study analysis assumed mobile or spare transformer availability. No study solution was necessary – load at risk less than 240 MWhr" as the solution for seven transformers with contingency concerns:

Washinton
New London
W. Cranston
Wampanoag
Valley
Newport
Tiverton

The Company's response to DIV 2-19a indicates that these seven transformers do not have an existing spare or mobile that can be used to restore customers. Where are the mobiles or spares that were assumed available at the time the Area Study was performed and why are they no longer available? Explain if these are the same transformers discussed in response to DIV 2-3.

Response:

The mobiles or spares that were assumed to be available at the time the Area Studies were performed are owned by National Grid and have remained with National Grid. These transformers are the same as those that the Company discussed in its response to DIV 2-3.

Division 7-5

Request:

For each station listed in response DIV 2-19d, identify any spare or mobile transformers that RIE proposes to purchase in order to resolve contingency load at risk.

Response:

Please see the table below summarizing where the proposed spare transformers and mobile substations can be used for each substation listed in DIV 2-19d.

Station	**Proposed Spare**	**Proposed Mobile**
Washington	115-13.2kV	115000V-13200Y/7620V
New London	115-13.2kV	115000V-13200Y/7620V
W. Cranston	115-13.2kV	115000V-13200Y/7620V
Wampanoag	115-13.2kV	115000V-13200Y/7620V
Staples	115-13.2kV	115000V-13200Y/7620V
Valley	115-13.2kV	115000V-13200Y/7620V
Dexter	115-13.2kV	115000V-13200Y/7620V
Tower Hill	115-13.2kV	115000V-13200Y/7620V
Chase Hill	115-13.2kV	115000V-13200Y/7620V
Newport	69-13.8kV	None
Tiverton	115-13.2kV	115000V-13200Y/7620V
Shun Pike	115-13.2kV	115000V-13200Y/7620V
Johnston	115-13.2kV	115000V-13200Y/7620V
Elmwood	None	34.5x23-12.47kV
Barrington	None	34.5x23-12.47kV

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

---

Division 7-6

Request:

Regarding Table 7 in Recommendation #15 Vegetation Management Cost-Benefit Analysis (Pre-file):

a. For each year, explain how each circuit and locations of work were selected for Pockets of Poor Performance, the date and work performed on each circuit, and associated cost.

b. Provide available performance results for each feeder listed in FY 21 and FY 22.

c. What are the protective devices shown in the FY 21 table? Explain how the work relates to the protective devices and to reporting. Are there protective devices associated with each feeder in the FY 22 table?

d. If the same circuit is listed in FY 21 and FY 22, did the Company address the circuit both years, but in a different location? Explain.

Response:

a. The Pocket of Poor Performance programs in FY 2021 and FY 2022 were designed to target specific areas that were suffering from repeated tree caused outages. On Bates page 154 of the FY 2021 Electric ISR, the Company states "In FY 2021, the Company projects an additional $0.2 million to focus on pockets of poor performance. These are areas where customers are experiencing many tree-related outages and the Company's routine pruning and hazard tree programs have not proven effective. The Company would like to take a more prescriptive approach and focus on trees outside our normal scope of work." Locations of the work were selected based on recommendations from the Reliability team including representatives of the Forestry department, which meets routinely throughout the year to discuss poor reliability areas. Data and decisions were made to a device level, (fuse, fuses, or pole top reclosure). Whole feeder solutions were evaluated at the Enhanced Hazardous Tree Mitigation (EHTM) program level or captured in an Engineering Reliability Review (ERR).

FY 2021 Locations

Protective device # 123883443 is a set of 3/100K fuses on Flat River Road in Greene, RI on the 54F1 feeder. Work was performed from Pole 614, Flat River Road to Pole 141 on Plainfield Pike. This 2.75-mile stretch is heavily wooded with both pine and oak trees and has 280 customers. At the time, Woodpecker Hill Nursing Home was a critical customer located on Plainfield Pike. Routinely during storms, Woodpecker Hill Nursing Home was one of the last critical customers to be restored due to the amount of tree damage that usually occurred on that section of wire. ABC Tree conducted operations in this area from 9/2/2020 to 11/2/2020. The cost of this work, including log removal, was $125,950.23.

Protective device #277314821 is a 65K line fuse located at Pole 45 on Maxson Hill Road in Hopkinton, RI. The specific area worked was on Collins Road and Tomaquag Road, which is on the 155F6 feeder and is approximately 6.5 miles long. This area of Hopkinton is a heavily treed hardwood forest that suffered significant Spongy Moth damage during the summer of 2016 and 2017. Multiple formal complaints due to poor reliability were filed. The Company worked with the Town to remove many dead trees and removed dead branches that could interrupt power. Lewis Tree worked this area from 1/18/2021 until 3/11/2021. The cost of the work was $33,944.20.

FY 2022 Locations

Protective device #277371321 is a set of 3/100 K fuses on Camp Westwood Road in Coventry, RI on the 54F1 feeder. The customer count for this stretch is low (18), however it is a feeder tie between Flat River Road and Harkney Hill Road. The area worked was from Pole 2 Camp Westwood to Pole 44, including Weeks Hill Road. This 1.5-mile stretch is heavily wooded. Stanley Tree conducted operations in this area from 1/4/2021 to 1/15/2021. The cost of this work including log removal was $32,234.34.

Protective device #277277773 is a 40 K fuse located at Pole 97, Poppasquash Road in Bristol, RI on the 51F3 feeder. The area worked was from Pole 97, Poppasquash Road to Clam Shell Road. This 1.08-mile stretch is heavily wooded, and a portion of it runs in wetlands. It feeds 10 customers. This pole line is in a very difficult spot to access and is challenging when there is storm damage or a tree failure. ABC Tree conducted operations on this area from 9/27/2021 to 10/2/2021. The cost of this work was $36,384.92.

Protective device #277312361 is a 25K line fuse at Pole 78, Woodville Road in Hopkinton, RI on the 85T1 feeder. The area worked is from Pole 78 to Pole 15, Woodville Road. This 3.31-mile stretch of Hopkinton is a heavily treed hardwood forest. This area also suffered significant Spongy Moth damage during the summer of 2016 and 2017. It is heavily wooded and has 69 customers. The Hopkinton DPW, the last customer on Woodville Road, frequently lost power due to tree issues. Davey Tree conducted operations in this area from 4/1/2021 to 5/5/2021. The cost of this work was $13,045.51.

Protective device #164130702 is a pole top recloser at pole 87, Tunk Hill Road on the 15F2 Feeder. The area worked is from pole 87 Tunk Hill Road to pole 226 Tunk Hill Road. This approximately 4.5 mile stretch of Scituate is a heavily treed hardwood forest. Providence Water owns most of the property that abuts the mainline. This area also suffered significant Spongy Moth damage during the summer of 2016 and 2017. It is heavily wooded and has 448 customers. ABC Tree conducted operations in this area from 11/1/2021 to 11/13/2021. The cost of this work was $75,946.46. Stanley Tree continued the project further down the road from 1/17/2022 to 2/5/2022. The cost of the additional Stanley Tree work was 53,534.56. The total cost for tree work in this area was $129,481.02.

b.

FY2021								
Excluding Major Events								
Feeder	Protective Device GIS ID	Events	Customers Interrupted	Customer Minutes				
56-155F6	277314821	10	1422	223,067				
56-54F1	123883443	8	583	77,409				
						Monthly	Monthly	Monthly
		18	2005	300,476		Avg Events	Monthly Avg CI	Monthly Avg CMI
		6	668.33	100158.67		0.5	55.69	8346.56
Feeder	Protective Device GIS ID	Events	Customers Interrupted	Customer Minutes				
56-155F6	277314821	0	0	0		Monthly	Monthly	Monthly
56-54F1	123883443	3	413	28883		Avg Events	Avg CI	Avg CMI
		3	413	28,883		0.08	11.47	802.31
					Average			
					Reduction	83.33%	79.40%	90.39%
Including Major Events								
Feeder	Protective Device GIS ID	Events	Customers Interrupted	Customer Minutes				
56-155F6	277314821	13	1,850	809,209				
56-54F1	123883443	18	1,789	1,414,989		Monthly	Monthly	Monthly
						Avg Events	Avg CI	Avg CMI
		31	3639	2,224,198		0.86	101.08	61783.28
		10.33	1213.00	741399.33				
Feeder	Protective Device GIS ID	Events	Customers Interrupted	Customer Minutes				
56-155F6	277314821	1	145	499,815		Monthly	Monthly	Monthly
56-54F1	123883443	5	671	210,767		Avg Events	Avg CI	Avg CMI
		6	816	710582		0.17	22.67	19738.39
					Average			
					Reduction	80.65%	77.58%	68.05%

FY2022								
Excluding Major Events								
Feeder	**Protective Device GIS ID**	**Events**	**Customers Interrupted**	**Customer Minutes**				
56-85T1	**277312361**	2	127	19,004				
53-51F3	**277277773**	3	29	6,675				
56-54F1	**277371321**	5	172	12,270				
53-15F2	**164130702**	4	1056	65,621		**Monthly**	**Monthly**	**Monthly**
		14	1384	103,570		**Avg Events**	**Avg CI**	**Avg CMI**
		4.67	461.33	34523.33		**0.39**	**38.44**	**2876.94**
Feeder	**Protective Device GIS ID**	**Events**	**Customers Interrupted**	**Customer Minutes**				
56-85T1	**277312361**	3	194	17,365		Only 2.5 years of Data		
53-51F3	**277277773**	0	0	0		**Monthly**	**Monthly**	**Monthly**
56-54F1	**277371321**	4	128	46708		**Avg Events**	**Avg CI**	**Avg CMI**
53-15F2	**164130702**	2	848	19,440		**0.30**	**39.00**	**2783.77**
		9	1170	83,513				
					Avg Reduction	**22.86%**	**-1.45%**	**3.24%**
Including Major Events								
Feeder	**Protective Device GIS ID**	**Events**	**Customers Interrupted**	**Customer Minutes**				
56-85T1	**277312361**	3	191	31,868				
53-51F3	**277277773**	3	29	6,675		**Monthly**	**Monthly**	**Monthly**
56-54F1	**277371321**	11	387	389,518		**Monthly Avg Events**	**Monthly Avg CI**	**Monthly Avg CMI**
53-15F2	**164130702**	9	2,043	423,592		**0.72**	**73.61**	**11890.58**
		26	2650	428,061				
		8.67	883.33	142687.00				
						Only 2.5 years of Data		
Feeder	**Protective Device GIS ID**	**Events**	**Customers Interrupted**	**Customer Minutes**		**Monthly**	**Monthly**	**Monthly**
56-85T1	**277312361**	3	194	17,365		**Avg Events**	**Avg CI**	**Avg CMI**
53-51F3	**277277773**	0	0	0		**0.40**	**51.17**	**7199.90**
56-54F1	**277371321**	6	212	156,712				
53-15F2	**164130702**	3	1129	41,920	**Avg Reduction**	**44.62%**	**30.49%**	**39.45%**
		12	1535	215997				

c. Please see the Company's response to part (a), above, which identifies protective devices associated with each area where the Company performed work, as identified on Table 7 for FY 2021 ad FY 2022. The protective devices are examined against each other to help select the appropriate areas to work on with this program. This coincides with how outage data is captured. In addition, customer count is captured readily by reference to the protective device. The protective devices for FY 2022 should have been listed in the FY 2022 Table. Going forward the Company will provide the information by protective device.

d. Yes, the Company worked on the 54F1 feeder in both FY 2021 and FY 2022, but in different locations. During FY 2021 and FY 2022, the Company did not focus on areas to perform this work by individual feeder. Rather, the focus was on protective devices and customers experiencing poor service quality. During FY 2024 and FY 2025, the Company will identify and address these types of areas by feeder.

Division 7-7

Request:

In executable format, provide all underlying data and calculations relied upon to develop the BCA for the ERR program (Attachment 9-2). Explain and include all assumptions, inputs and calculations used to determine the costs and benefits of the expected reliability improvements each year.

Response:

The Excel version of Attachment DIV 7-7 provides the underlying data and calculations relied upon to develop the BCA for the Engineering Reliability Review ("ERR") program (Attachment 9-2), including all assumptions, inputs and calculations used to determine the costs and benefits of the expected reliability improvements.

Division 7-8

Request:

The FY 2025 ISR Filing states that the exact details of potential Infrastructure Investment and Jobs Act ("IIJA") cost match for RIE's funding proposal "have yet to be finalized within the award negotiation process." (page 77) What is involved in an award negotiation process? What parties are negotiating and who is leading the negotiations on behalf of RIE? What is RIE's proposed position, specifically how much federal funding is RIE requesting and if successfully negotiated, what programs or projects would receive the federal funding and over what time period would RIE make the investments?

Response:

The award negotiation process is an in-depth review of the proposed project by staff representing the U.S. Department of Energy (DOE)[1] in collaboration with the Project Team (in this case, Rhode Island Energy as the prime applicant). The award negotiation process involves multiple deliverables, including but not limited to a Cybersecurity Plan, Community Benefits Plan, and Statement of Project Objectives (akin to a detailed work plan with deliverables, milestones, and go/no-go decision points). These deliverables undergo an iterative development, review, and revision process to ensure they meet the requirements set forth by DOE and are in compliance with relevant statutes. The whole of this iterative process and related communications between the Project Team and DOE is referred to as the "negotiation."

The Company has a team of staff who are participating in the negotiation:

- Kathy Castro, Director of Planning and Asset Management, Principal Investigator and Technical Lead;
- Brian Grzesiuk, Senior Financial Manager, Business Lead;
- Carrie Gill, Senior Manager of Electric Regulatory Strategy;
- Kimberly Spotts-Kimmel, Senior Counsel for PPL; and
- Other subject matter experts as needed.

Award negotiations have not yet entailed discussion of any party's positions on final award amounts. Rhode Island Energy's position is that the full $50 million requested is appropriate to achieve the objectives set forth in Rhode Island Energy's application, in line with the stated objectives of the Funding Opportunity Announcement and as aligned with the Infrastructure Investment and Jobs Act (also referred to as the Bipartisan Infrastructure Law). Rhode Island Energy was selected for award negotiations for a portfolio of spending that includes both

[1] US DOE contracts with the National Energy Technology Lab (NETL) for project administrative support.

hardware and software (i.e., operational technology, information technology, and communications). In practice, Rhode Island Energy would propose that the federal funding offset costs for advanced reclosers, advanced capacitors and regulators, and electromechanical digital relays, funding for which would otherwise be requested to be funded via customer-sourced cost recovery (e.g., the annual ISR). The grant period of performance is 60 months; Rhode Island Energy would spend down the entirety of the federal funding within this period of performance.

Prepared by or under the supervision of: Kathy Castro

Division 7-9

Request:

What is the age of the Westerly #2 transformer that failed?

Response:

The Westerly #2 transformer was 47 years old at the time of failure.

Division 7-10

Request:

Provide circuit level reliability statistics (CKAIFI and CKAIDI) for Tiverton 33F1, 33F2, 33F3, and 33F4 for the past six years.

Response:

Regulatory reported reliability statistics for the Tiverton circuits from 2018 through 2023 are listed below.

Circuit	Year	SAIFI	SAIDI
56-33F1	2018	1.19	76.7
56-33F1	2019	0.4964	23.9495
56-33F1	2020	0.6116	32.8844
56-33F1	2021	2.0255	68.2502
56-33F1	2022	0.0918	8.7326
56-33F1	2023	0.0354	2.9482
56-33F2	2018	0.10	10.7
56-33F2	2019	1.1753	46.263
56-33F2	2020	0.119	13.6137
56-33F2	2021	0.0818	5.7241
56-33F2	2022	0.1097	10.0018
56-33F2	2023	0.0348	3.1028
56-33F3	2018	0.56	51.4
56-33F3	2019	1.6355	72.7884
56-33F3	2020	0.6588	68.3723
56-33F3	2021	0.221	26.6021
56-33F3	2022	0.9384	50.2538
56-33F3	2023	1.0158	51.5366
56-33F4	2018	0.73	76.1
56-33F4	2019	4.0387	173.0161
56-33F4	2020	1.9976	111.5768
56-33F4	2021	3.7119	199.012
56-33F4	2022	0.4125	41.9817
56-33F4	2023	0.4433	26.9564

Prepared by or under the supervision of: Ryan Constable

Division 7-11
Revenue Requirements

Request:

Referring to Section 5, Attachment 1, Page 24, Line 2, please provide documentation from the Tax Department supporting the Capital Repairs Deduction Rate of 8.51%.

Response:

Section 5, Attachment 1, Page 24 provides the tax deduction calculations for FY 2024 in Docket No. 22-53-EL. Pursuant to past practice utilized by National Grid during its ownership of the Narragansett Electric Company ("the Company"), the capital repairs deduction rate ("repairs rate") was based upon the latest filed Federal tax return, which, in this case, would be the FY 2022 tax return. The Company, however, received National Grid's repairs rate per National Grid's final FY 2022 Federal tax return towards the end of the ISR preparation process and the Company inadvertently missed updating the repairs rate. Consequently, the Company used the estimated FY 2022 repairs rate that was filed with the FY 2022 ISR plan year in Docket No. 5098. This FY 2022 repairs rate was based on the filed FY 2020 Federal tax return and the results are reflected below.

Qualifying FY2020 additions for repair deductions	$104,855,951
Repairs deduction per the FY2020 tax return	$ 8,923,009
Repairs rate per qualifying additions	8.51%

The actual repairs rate computed from National Grid's FY 2022 tax return is presented below, and the Company plans to reflect this update in the FY 2024 Electric ISR reconciliation, which is expected to be filed by August 1, 2024. The actual repairs rate for FY 2024 will not be final until the Company files its calendar year 2024 tax return in October of 2025.

Qualifying FY2022 additions for repair deductions	$101,087,492
Repairs deduction per the FY2022 tax return	$ 29,990,554
Repairs rate per qualifying additions	29.67%

Prepared by or under the supervision of: Natalie Hawk

Division 7-12
Revenue Requirements

Request:

Referring to Section 5, Attachment 1, Page 24, Line 2, please explain why the Capital Repairs Deduction Rate of 8.51% for FY 2024 Incremental Capital Investments is so much lower than the Capital Repairs Deduction Rate for the years 2021-2023.

Response:

Please see the response to Division 7-11. If the Company used the capital repairs deduction rate ("repairs rate") of 29.67% from the FY 2022 tax return, the repairs rate in FY 2024 would be more in line with the repairs rates for years 2021-2023. In addition, it is important to note that the repairs deduction rates are computed by dividing the repairs deduction on the tax return by book additions placed in service within the same year. The repairs deduction on the tax return depends on whether the projects placed in service in a particular year satisfy the requirements set forth by the Internal Revenue Code and Tangible Property Regulations. Consequently, the repairs deduction rates will vary from year to year and may not provide insights concerning repairs deductions in future periods. The repairs rates are utilized only for estimation purposes.

Prepared by or under the supervision of: Natalie Hawk

Division 7-13
Revenue Requirements

Request:

Referring to Section 5, Attachment 2, Page 2, please provide workpapers supporting the amounts in the "No Acquisition" Column.

Response:

Please see Attachment Division 7-13 for the requested information. The amounts in the "No Acquisition" column can be found on the "Average ISR Rate Base after Deferred Tax Proration Adjustment line" of each fiscal year's revenue requirement. Also, these calculations can be found on the green tabs towards the back of the Excel file that was submitted in the Company's filing on December 21, 2023.

Prepared by or under the supervision of: Natalie Hawk

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)	NG 4/1/22 - 5/24/2022 2023 (f)	PPL 5/25/22 - 3/31/23 2023 (g)	Fiscal Year 2024 (h)	Fiscal Year 2025 (i)
	Capital Investment Allowance											
1	*Non-Discretionary Capital*			$1,828,121								
	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 29 of 38, Line 4(a)		$16,466,377	$0	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base											
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$16,466,377	$0	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 38 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$21,711,449	$21,711,449	$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	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$16,466,377	$16,466,377	$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 29 of 38 , Line 7 ,Col (a)		$1,693,009	$0	$0	$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**	**$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%	3.16%	3.16%
13	number of days								54	311		
14	Proration Percentage								14.79%	85.21%		
15	Vintage Year Tax Depreciation:											
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 3 of 38, Line 29; then = Page 3 of 38, Column (b)		$13,098,604	$527,752	$488,128	$451,575	$417,654	$57,161	$329,204	$357,342	$330,585
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$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 = Prior Year Line 17 + Current Year Line 16; then = Prior Year Line 18 + Current Year Line 16								$15,370,078	$15,727,420	$16,058,005
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$369,095	$707,793	$686,082	$686,082	$686,082	$101,503	$584,579	$686,082	$686,082
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	$4,507,297	$5,193,379
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	$11,548,863	$11,220,123	$10,864,626
22	Less: Cumulative Book Depreciation at Acquisition	Not Applicable if Acquisition doesn't take place										
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22								$11,548,863	$11,220,123	$10,864,626
24	Effective Tax Rate		2/	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (f): Line 21 * Line 24, Then Line 23 * Line 24		$2,673,197	$2,635,388	$2,593,818	$2,544,572	$2,488,202	$2,478,890	$2,425,261	$2,356,226	$2,281,572
26	Less: FY 2018 Federal NOL (Generation) / Utilization	Year 1 = Page 29 of 38 , Line 15 ,Col (a) ; then = Prior Year Line 26		($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)
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	$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	$769,726	$700,691	$626,036
	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	$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)	($4,507,297)	($5,193,379)
31	Deferred Tax Reserve	-Line 28		($1,017,662)	($979,853)	($938,283)	($889,036)	($832,667)	($823,355)	($769,726)	($700,691)	($626,036)
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	$13,568,445	$12,951,399	$12,339,971
	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)		$8,386,315	$16,437,637	$15,780,389	$15,139,716	$14,506,442	$13,880,016	$13,880,016	$13,259,922	$12,645,685
34	Proration Adjustment	Page 4 of 38 & Page do not print of 38				($1,784)	($2,114)	($2,420)	($2,702)	($2,702)	($2,963)	($3,204)
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	$13,877,314	$13,877,314	$13,256,959	$12,642,481
36	Pre-Tax ROR	Page 37 of 38, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
37	Proration	Line 14							14.79%	85.21%		
38	Return and Taxes	Cols (a) through (e) and (j): L 35 * L 36; Cols (f) through (i): L 35 * L 36 * L 37		$690,194	$1,352,818	$1,298,579	$1,245,825	$1,193,681	$168,969	$973,134	$1,091,048	$1,040,476
39	Book Depreciation	Line 19		$369,095	$707,793	$686,082	$686,082	$686,082	$101,503	$584,579	$686,082	$686,082
40	**Annual Revenue Requirement**	Line 38 + Line 39		**$1,059,288**	**$2,060,611**	**$1,984,661**	**$1,931,906**	**$1,879,763**	**$270,471**	**$1,557,714**	**$1,777,129**	**$1,726,558**

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/ The Federal Income Tax rate changed from 35% to 21% on Janurary 1, 2018 per the Tax Cuts and Jobs Act of 2017

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.			Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)	NG 4/1/22 - 5/24/2022 FY 2023 (e)	PPL 5/25/22 - 3/31/23 2023 (f)	Fiscal Year 2024 (g)	Fiscal Year 2025 (h)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*		$6,261,278							
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 29 of 38, Line 4(b)	$31,748,054	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base									
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)	$31,748,054	$0	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 38 , Line 10 ,Col (b)	($10,649,479)	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6	$42,397,533	$42,397,533	$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	$0	$0
8	Depreciation Expense		$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9	$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054	$31,748,054
10	Cost of Removal	Page 29 of 38 , 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**	**$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%	3.16%	3.16%
13	Number of days						54	311		
14	Proration Percentage						14.79%	85.21%		
15	Vintage Year Tax Depreciation:									
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 6 of 38, Line 28 Then = Page 6 of 38 Column (b)	$9,877,791	$1,776,194	$1,642,838	$1,519,816	$207,959	$1,197,692	$1,300,344	$1,202,664
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	$9,877,791	$11,653,985	$13,296,823	$14,816,638	$15,024,597			
18	Cumulative Tax Depreciation-PPL	Year 1 = Prior Year Line 17 + Current Year Line 16; then = Prior Year Line 18 + Current Year Line 16						$16,222,289	$17,522,633	$18,725,298
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	$691,080	$1,339,762	$1,339,762	$1,339,762	$198,211	$1,141,551	$1,339,762	$1,339,762
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	$7,389,890	$8,729,652
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	$10,172,161	$10,132,743	$9,995,646
22	Less: Cumulative Book Depreciation at Acquisition	Not Applicable if Acquisition doesn't take place								
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22						$10,172,161	$10,132,743	$9,995,646
24	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (e): Line 21 * Line 24, Then Line 23 * Line 24	$1,929,209	$2,020,860	$2,084,506	$2,122,317	$2,124,364	$2,136,154	$2,127,876	$2,099,086
26	Add: FY 2019 Federal NOL (Generation) / Utilization	Page 29 of 38 , Line 15 ,Col (b)	$991,622	$991,622	$991,622	$991,622	$991,622	$991,622	$991,622	$991,622
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	$3,127,776	$3,119,498	$3,090,707
	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	$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)	($7,389,890)	($8,729,652)
30	Deferred Tax Reserve	-Line 27	($2,920,831)	($3,012,482)	($3,076,128)	($3,113,939)	($3,115,986)	($3,127,776)	($3,119,498)	($3,090,707)
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	$22,931,873	$21,600,389	$20,289,418
	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	$14,248,933	$27,782,160	$26,364,749	$24,974,259	$23,608,673	$23,608,673	$22,266,131	$20,944,903
33	Proration Adjustment	& Page do not print of 38	$0	$0	$0	($522)	($3,862)	($3,862)	($4,811)	($5,692)
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	$23,604,811	$23,604,811	$22,261,320	$20,939,212
35	Pre-Tax ROR	Page 37 of 38, Line 35	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration Percentage	Line 14					14.79%	85.21%		
37	Return and Taxes	Cols (a) through (d) and (i): L 34 * L 35; Cols (e) through (h): L 34 * L 35 * L 36	$1,172,687	$2,286,472	$2,169,819	$2,055,339	$287,410	$1,655,266	$1,832,107	$1,723,297
38	Book Depreciation	Line 19	$691,080	$1,339,762	$1,339,762	$1,339,762	$198,211	$1,141,551	$1,339,762	$1,339,762
39	Annual Revenue Requirement	Line 37 + Line 38	$1,863,767	$3,626,234	$3,509,581	$3,395,101	$485,621	$2,796,817	$3,171,869	$3,063,059
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	$485,621	$2,796,817	$3,171,869	$3,063,059
41	Revenue Requirement of Intangible	Page 8 of 38, of FY19 Intg No Acq Tab Line32	$434,302	$705,779	$655,914	$617,127	$81,808	$501,170	$550,625	$518,482
42	**Revenue Requirement**	Line 40 + Line 41	**$1,521,500**	**$4,332,013**	**$4,165,495**	**$4,012,227**	**$567,429**	**$3,297,987**	**$3,722,494**	**$3,581,541**

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	FY19 Total (c) = (a) + (b)	FY 20 Total (f) = (d) + (e)	FY 21 Total (i) = (g) + (h)	FY 22 Total (l) = (j) + (k)	FY Mar-2023 (Apr-May 2022) (o) = (m) + (n)	FY Mar-2023 (Jun 2022 - Mar 2023) (r) = (p) + (q)	FY Mar-2024 (Apr 2023 - Mar 2024) (u) = (s) + (t)	FY Mar-2025 (Apr 2024 - Mar 2025) (x) = (v) + (w)
	Capital Investment						NG	PPL	PPL	PPL
1	Start of Rev. Req. Period		09/01/18	04/01/19	04/01/20	04/01/21	04/01/22	05/25/22	04/01/23	04/01/24
2	End of Rev. Req. Period		03/31/19	03/31/20	03/31/21	03/31/22	05/24/22	03/31/23	03/31/24	03/31/25
3	Investment Name	Per Company's Book								
4	Work Order	Per Company's Book								
5	Total Spend		$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626
6	In ServiceDate	Per Company's Book								
7	Book AmortizationPeriod	Per Company's Book								
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$3,378,230	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,540,045	$1,112,344	$617,969
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,540,045	$1,112,344	$617,969	$123,594
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$1,573,382	$1,326,195	$865,157	$370,781
	Deferred Tax Calculation:									
11	Tax Amortizaton Period	Page 9 of 38								
12	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department								
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0	$0	$0	$0	$0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (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	$3,460,626	$3,460,626	$3,460,626
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (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	$3,460,626	$3,460,626	$3,460,626
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410	$3,460,626	$3,460,626	$3,460,626	$3,460,626
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$82,396	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581	$2,348,282	$2,842,657
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$370,781	$865,157	$1,359,532	$1,853,907	$1,920,581	$2,348,282	$2,842,657	$3,337,032
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719	$1,887,244	$2,134,432	$2,595,470	$3,089,845
21	Number of days									
22	Proration Percentage									
23	Average Book / Tax Timer	Line 17 - Line 20	$926,838	$1,304,582	$1,835,590	$1,725,691	$232,774	$1,129,991	$865,157	$370,781
24	Effective Tax Rate									
25	Deferred Tax Reserve	Line 23 × Line 24	$194,636	$273,962	$385,474	$362,395	$48,883	$237,298	$181,683	$77,864
	Rate Base Calculation:									
26	Average Book Balance	Line 10	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$232,774	$1,129,991	$865,157	$370,781
27	Deferred Tax Reserve	Line 25	$194,636	$273,962	$385,474	$362,395	$48,883	$237,298	$181,683	$77,864
28	Average Rate Base	Line 26 - Line 27	$3,039,402	$2,568,695	$1,962,808	$1,491,512	$183,892	$892,693	$683,474	$292,917
	Revenue Requirement Calculation:									
29	Pre-Tax ROR	year 1 = Page 37 of 38, Line 27, column (e)×7÷12 Then = Page 37 of 38, Line 27(e)								
30	Return and Taxes	Line 28 × Line 29	$145,917	$211,404	$161,539	$122,751	$15,134	$73,469	$56,250	$24,107
31	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375	$66,674	$427,701	$494,375	$494,375
32	Annual Revenue Requirement	Line 30 + Line 31	$434,302	$705,779	$655,914	$617,127	$81,808	$501,170	$550,625	$518,482

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2020 Actual Incremental Capital Investment

Line No.			Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)	NG 4/1/22 - 5/24/2022 FY 2023 (d)	PPL 5/25/22 - 3/31/23 2023 (e)	Fiscal Year 2024 (f)	Fiscal Year 2025 (g)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*		$27,837,942						
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending		$39,597,335						
3	Total Allowed Capital Included in Rate Base	Page 29 of 38, Line 4(c)	$67,435,277	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base								
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3	$67,435,277	$0	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 38 , Line 10 ,Col (c)	$4,015,632	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6	$63,419,645	$63,419,645	$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	$0	$0
8	Depreciation Expense	Page 33 of 38, Line 41, Col (d) ×7 ÷12	$29,112,370	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9	$38,322,907	$38,322,907	$38,322,907	$38,322,907	$38,322,907	$38,322,907	$38,322,907
10	Cost of Removal	Page 29 of 38 , 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**	**$49,655,625**	**$49,655,625**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 31 of 38, Line 3, Col (e) 1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days					54	311		
14	Proration Percentage					14.79%	85.21%		
15	Vintage Year Tax Depreciation:								
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 11 of 38, Line 28, Then = Page 11 of 38, Column (d)	$23,504,007	$4,305,759	$3,982,484	$545,069	$3,139,192	$3,407,508	$3,152,229
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	$23,504,007	$27,809,766	$31,792,250	$32,337,319			
18	Cumulative Tax Depreciation-PPL	Year 1 = Prior Year Line 17 + Current Year Line 16; then = Prior Year Line 18 + Current Year Line 16					$35,476,510	$38,884,019	$42,036,247
19	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	$1,002,030	$2,004,061	$2,004,061	$296,491	$1,707,570	$2,004,061	$2,004,061
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19	$1,002,030	$3,006,091	$5,010,152	$5,306,643	$7,014,213	$9,018,274	$11,022,334
21	Cumulative Book / Tax Timer	Columns (a) through (d): Line 17 - Line 20, Then Line 18 - Line 20	$22,501,976	$24,803,674	$26,782,098	$27,030,675	$28,462,298	$29,865,745	$31,013,913
22	Less: Cumulative Book Depreciation at Acquisition	Not Applicable if Acquisition doesn't take place							
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$28,462,298	$29,865,745	$31,013,913
24	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (d): Line 21 * Line 24, Then Line 23 * Line 24	$4,725,415	$5,208,772	$5,624,241	$5,676,442	$5,977,082	$6,271,806	$6,512,922
26	Add: FY 2020 Federal NOL (Generation) / Utilization	Page 29 of 38, Line 15, Col (c)	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26	$3,262,435	$3,745,791	$4,161,260	$4,213,461	$4,514,102	$4,808,826	$5,049,941
	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	$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)	($9,018,274)	($11,022,334)
30	Deferred Tax Reserve	-Line 27	($3,262,435)	($3,745,791)	($4,161,260)	($4,213,461)	($4,514,102)	($4,808,826)	($5,049,941)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30	$45,391,160	$42,903,743	$40,484,213	$40,135,521	$38,127,310	$35,828,526	$33,583,350
	Revenue Requirement Calculation:								
32	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 31 * Page 16 of 38, Line 16, Col(e); Then =(Prior Year Line 31 + Current Year Line 31) ÷ 2	$16,573,333	$44,147,452	$41,693,978	$39,305,762	$39,305,762	$36,977,918	$34,705,938
33	Proration Adjustment	, Line 41, Column (h)	$30,912	$18,700	$17,833	$15,145	$15,145	$12,650	$10,349
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34	$16,604,245	$44,166,151	$41,711,811	$39,320,907	$39,320,907	$36,990,568	$34,716,287
35	Pre-Tax ROR	Page 37 of 38, Line 35	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14				14.79%	85.21%		
37	Return and Taxes	Cols (a) through (c) and (h): L 34 * L 35; Cols (d) through (g): L 34 * L 35 * L 36	$1,366,529	$3,634,874	$3,432,882	$478,767	$2,757,344	$3,044,324	$2,857,150
38	Book Depreciation	Line 19	$1,002,030	$2,004,061	$2,004,061	$296,491	$1,707,570	$2,004,061	$2,004,061
39	**Annual Revenue Requirement**	Line 37 + Line 38	**$2,368,560**	**$5,638,935**	**$5,436,943**	**$775,258**	**$4,464,913**	**$5,048,385**	**$4,861,211**

40 Docket No. 4915, FY 2020 Electric ISR Reconciliation, Page 9, Line 29
41 2020 Tax True Up

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2021 Actual Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	NG 4/1/22 - 5/24/2022 FY 2023 (c)	PPL 5/25/22 - 3/31/23 2023 (d)	Fiscal Year 2024 (e)	Fiscal Year 2025 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*			$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 29 of 38, Line 4(d)		$115,360,166	$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		$115,360,166	$0	$0	$0	$0	$0
5	Retirements	Page 29 of 38 , Line 10 ,Col (d)		$21,996,026	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$93,364,140	$93,364,140	$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	$0	$0
8	Depreciation Expense	Page 33 of 38, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$65,453,245	$65,453,245	$65,453,245	$65,453,245	$65,453,245	$65,453,245
10	Cost of Removal	Page 29 of 38 , 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**	**$75,686,055**	**$75,686,055**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	Page 31 of 38, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days					54	311		
14	Proration Percentage					14.79%	85.21%		
15	Vintage Year Tax Depreciation:								
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 14 of 38, Line 28, Column (a), Then = Line Page 14 of 38 , Column (d)		$44,175,121	$6,372,048	$871,935	$5,021,702	$5,452,299	$5,042,736
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$44,175,121	$50,547,169	$51,419,105			
18	Cumulative Tax Depreciation-PPL	Year 1 = Prior Year Line 17 + Current Year Line 16; then = Prior Year Line 18 + Current Year Line 16					$56,440,807	$61,893,105	$66,935,841
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	$2,950,307	$2,950,307
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	$10,326,074	$13,276,381
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	$49,065,040	$51,567,031	$53,659,461
22	Less: Cumulative Book Depreciation at Acquisition	Not Applicable if Acquisition doesn't take place	3/						
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22					$49,065,040	$51,567,031	$53,659,461
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (c): Line 21 * Line 24, Then Line 23 * Line 24		$8,966,993	$9,685,559	$9,777,004	$10,303,658	$10,829,077	$11,268,487
26	Add: FY 2021 Federal NOL (Generation) / Utilization	Page 29 of 38, Line 15, Col (d)		($5,639,147)	($5,639,147)	($5,639,147)	($5,639,147)	($5,639,147)	($5,639,147)
27	Net Deferred Tax Reserve beforee Proration Adjustment	Sum of Lines 25 through 26		$3,327,846	$4,046,411	$4,137,856	$4,664,511	$5,189,929	$5,629,339
	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	$75,686,055	$75,686,055
29	Accumulated Depreciation	-Line 20		($1,475,153)	($4,425,460)	($4,861,944)	($7,375,767)	($10,326,074)	($13,276,381)
30	Deferred Tax Reserve	-Line 27		($3,327,846)	($4,046,411)	($4,137,856)	($4,664,511)	($5,189,929)	($5,629,339)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$70,883,056	$67,214,184	$66,686,255	$63,645,777	$60,170,052	$56,780,335
	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		$35,441,528	$69,048,620	$65,429,980	$65,429,980	$61,907,915	$58,475,194
33	Proration Adjustment	, Line 41		$16,539	$30,843	$26,530	$26,530	$22,552	$18,861
34	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		$35,458,067	$69,079,462	$65,456,511	$65,456,511	$61,930,467	$58,494,054
35	Pre-Tax ROR	Page 37 of 38, Line 35		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14				14.79%	85.21%		
37	Return and Taxes	Cols (a),(b) and (f): L 34 * L 35; Cols (c) through (f): L 34 * L 35 * L 36		$2,918,199	$5,685,240	$796,991	$4,590,080	$5,096,877	$4,814,061
38	Book Depreciation	Line 19		$1,475,153	$2,950,307	$436,484	$2,513,823	$2,950,307	$2,950,307
39	Revenue Requirement of Intangible Assets								
40	**Annual Revenue Requirement**	**Line 37 + Line 38 + Line 39**		**$4,393,352**	**$8,635,547**	**$1,233,475**	**$7,103,903**	**$8,047,184**	**$7,764,367**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2022 Actual Incremental Capital Investment

Line No.				Fiscal Year 2022 (a)	NG 4/1/22 - 5/24/2022 FY 2023 (b)	PPL 5/25/22 - 3/31/23 FY 2023 (c)	Fiscal Year 2024 (d)	Fiscal Year 2025 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*	Docket 5098, P 29 of 29. Line 1(a)		$44,263,589				
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				$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 29 of 38, Line 4(e)		$86,464,019	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$86,464,019	$0	$0	$0	$0
5	Retirements	Page 29 of 38 , Line 10 ,Col (e)		$34,853,004	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$51,611,015	$51,611,015	$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	$0	$0
8	Depreciation Expense	Page 33 of 38, Line 62, Col (d)		$49,906,920	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$36,557,099	$36,557,099	$36,557,099	$36,557,099	$36,557,099
10	Cost of Removal	Page 29 of 38 , Line 7 ,Col (e)		$7,600,505	$0	$0	$0	$0
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$44,157,603**	**$44,157,603**	**$44,157,603**	**$44,157,603**	**$44,157,603**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	Page 31 of 38, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%	3.16%
13	Number of days				54	311		
14	Proration Percentage				14.79%	85.21%		
15	Vintage Year Tax Depreciation:							
16	Tax Depreciation and Year 1 Basis Adjustments	Year 1 = Page 18 of 38, Line 27, Column (a), Then = Line Page 18 of 38 , Column (e)		$41,638,714	$649,462	$3,740,422	$4,060,293	$3,756,243
17	Cumulative Tax Depreciation-NG	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$41,638,714	$42,288,176			
18	Cumulative Tax Depreciation-PPL	Year 1 = Prior Year Line 17 + Current Year Line 16; then = Prior Year Line 18 + Current Year Line 16				$46,028,598	$50,088,891	$53,845,134
19	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$815,454	$241,285	$1,389,623	$1,630,908	$1,630,908
20	Cumulative Book Depreciation	Year 1 = Line 19; then = Prior Year Line 20 + Current Year Line 19		$815,454	$1,056,739	$2,446,362	$4,077,270	$5,708,178
21	Cumulative Book / Tax Timer	Columns (a) and (b): Line 17 - Line 20, Then Line 18 - Line 20		$40,823,260	$41,231,437	$43,582,236	$46,011,621	$48,136,956
22	Less: Cumulative Book Depreciation at Acquisition	Not Applicable if Acquisition doesn't take place	3/					
23	Cumulative Book / Tax Timer - PPL	Line 21 + Line 22				$43,582,236	$46,011,621	$48,136,956
24	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%	21.00%
25	Deferred Tax Reserve	Columns (a) through (b): Line 21 * Line 24, Then Line 23 * Line 24		$8,572,885	$8,658,602	$9,152,270	$9,662,440	$10,108,761
26	Add: FY 2022 Federal NOL (Generation) / Utilization	Page 29 of 38, Line 15, Col (e)		($3,602,966)	($3,602,966)	($3,602,966)	($3,602,966)	($3,602,966)
27	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 25 through 26		$4,969,918	$5,055,636	$5,549,304	$6,059,474	$6,505,795
	Rate Base Calculation:							
28	Cumulative Incremental Capital Included in Rate Base	Line 11		$44,157,603	$44,157,603	$44,157,603	$44,157,603	$44,157,603
29	Accumulated Depreciation	-Line 20		($815,454)	($1,056,739)	($2,446,362)	($4,077,270)	($5,708,178)
30	Deferred Tax Reserve	-Line 27		($4,969,918)	($5,055,636)	($5,549,304)	($6,059,474)	($6,505,795)
31	Year End Rate Base before Deferred Tax Proration	Sum of Lines 28 through 30		$38,372,231	$38,045,228	$36,161,938	$34,020,859	$31,943,630
	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		$19,186,115	$37,267,084	$37,267,084	$35,091,398	$32,982,244
33	Proration Adjustment	Columns (a) through (e) see , Line 41; Column (f) see Page do not print of 38, Line 41		$13,204	$24,869	$24,869	$21,898	$19,157
34	Average ISR Rate Base after Deferred Tax Proration	Line 33 + Line 34		$19,199,320	$37,291,953	$37,291,953	$35,113,296	$33,001,402
35	Pre-Tax ROR	Page 37 of 38, Line 33		8.23%	8.23%	8.23%	8.23%	8.23%
36	Proration	Line 14			14.79%	85.21%		
37	Return and Taxes	Cols (a) and (f): L 34 * L 35; Cols (b) through (e): L 34 * L 35 * L 36		$1,580,104	$454,063	$2,615,065	$2,889,824	$2,716,015
38	Book Depreciation	Line 19		$815,454	$241,285	$1,389,623	$1,630,908	$1,630,908
39	**Annual Revenue Requirement**	**Line 37 + Line 38**		**$2,395,558**	**$695,348**	**$4,004,688**	**$4,520,732**	**$4,346,923**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Fiscal Year 2025 Revenue Requirement on FY 2023 Actual Incremental Capital Investment

Line No.				NG 4/1/22 - 5/24/2022 2023 (a)	PPL 5/25/22 - 3/31/23 2023 (b)	Fiscal Year 2024 (c)	Fiscal Year 2025 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*	Page do not print of 38, Line 1		$6,130,225	$35,305,558		
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Page do not print of 38, Line 13		$7,632,024	$43,954,804		
3	Total Allowed Capital Included in Rate Base (non-intangible)	Sum of Lines 1 through 2		$13,762,249	$79,260,362	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,762,249	$79,260,362		
5	Retirements	Company's Record		$2,633,153	$15,165,012		
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$11,129,096	$64,095,350	$75,224,446	$75,224,446
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$13,762,249	$79,260,362		
8	Depreciation Expense	Page 33 of 38, Line 62, Col (d)		$7,383,490	$42,523,431		
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$6,378,760	$36,736,931	$43,115,691	$43,115,691
10	Cost of Removal	Company's Record		$1,142,377	$6,579,244		
11	**Total Net Plant in Servic**	**Line 9 + Line 10**		**$7,521,136**	**$43,316,175**	**$50,837,312**	**$50,837,312**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	Page 31 of 38, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%
13	Proration Percentage						
14	Vintage Year Tax Depreciation:						
15	Tax Depreciation and Year 1 Basis Adjustments	Col (a) = Page 21 of 38, Column (a), Line 27; Col (b) = Page 21 of 38, Col (b), Lines 18,24,25 + Col (e), Line 15, Then remaining years from Page 21 of 38, Col (e)		$6,050,145	$34,844,358	$4,969,324	$4,596,229
16	Cumulative Tax Depreciation-NG	Prior Year Line 15 + Current Year Line 14		$6,050,145			
17	Cumulative Tax Depreciation-PPL	Year 1 = Line 15, Columns (b) and (c); then = Prior Year Line 17 + Current Year Line 15			$40,894,503	$45,863,827	$50,460,055
18	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$175,840	$1,012,707	$2,377,093	$2,377,093
19	Cumulative Book Depreciation	Prior Year Line 19 + Current Year Line 17		$175,840	$1,188,546	$3,565,639	$5,942,731
20	Book / Tax Timer	Line 16 - Line 18		$5,874,306	$33,831,651	$2,592,231	$2,219,136
	Cumulative Book / Tax Timer -NG			$5,874,306		$5,874,306	$5,874,306
21	Cumulative Book / Tax Timer - PPL	Line 20, Column (a)			$33,831,651	$36,423,882	$38,643,018
22	Cumulative Book / Tax Timer - Total			$5,874,306	$33,831,651	$42,298,188	$44,517,324
23	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
24	Deferred Tax Reserve	Line 22 * Line 23		$1,233,604	$7,104,647	$8,882,619	$9,348,638
25	Add: FY 2023 Federal NOL (Generation) / Utilization	Company's Record		$23,627,830	$23,627,830	$23,627,830	$23,627,830
26	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 24 through 25		$24,861,434	$30,732,477	$32,510,449	$32,976,468
	Rate Base Calculation:						
27	Cumulative Incremental Capital Included in Rate Base	Line 11		$7,521,136	$43,316,175	$50,837,312	$50,837,312
28	Accumulated Depreciation	-Line 19		($175,840)	($1,012,707)	($3,565,639)	($5,942,731)
29	Deferred Tax Reserve	-Line 26		($24,861,434)	($30,732,477)	($32,510,449)	($32,976,468)
30	Year End Rate Base before Deferred Tax Proratior	Sum of Lines 27 through 29		($17,516,137)	$11,570,992	$14,761,223	$11,918,112
	Revenue Requirement Calculation:						
31	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 30 * 50%; Then = (Prior Year Line 30 + Current Year Line 30) ÷ 2		($8,758,069)	$5,785,496	$4,408,039	$13,339,668
32	Proration Adjustment	Columns (d) and (e) see , Line 41; Column (f) see Page do not print of 38, Line 41		$10,400	$59,893	$23,366	$20,003
33	Average ISR Rate Base after Deferred Tax Proration	Line 32 + Line 33		($8,747,669)	$5,845,389	$4,431,405	$13,359,670
34	Pre-Tax ROR	Page 37 of 38, Line 33		8.23%	8.23%	8.23%	8.23%
35	Proration						
36	Return and Taxes	Line 33 * Line 34		($719,933)	$481,076	$364,705	$1,099,501
37	Book Depreciation	Line 18		$175,840	$1,012,707	$2,377,093	$2,377,093
38	**Annual Revenue Requiremen**	**Line 36 + Line 37**		**($544,093)**	**$1,493,782**	**$2,741,797**	**$3,476,593**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 31 of 38, Line 3, Col (e))

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.

______________________________ February 7, 2024

Joanne M. Scanlon Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
Service List as of 1/10/2024

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. 280 Melrose St. Providence, RI 02907 Adam S. Ramos, Esq. **Hinckley Allen** 100 Westminster Street, Suite 1500 Providence, RI 02903-2319	amarcaccio@pplweb.com; cobrien@pplweb.com; jscanlon@pplweb.com; aramos@hinckleyallen.com; sbriggs@pplweb.com; NABegnal@RIEnergy.com; smtoronto@RIEnergy.com; ATLaBarre@RIEnergy.com; rconstable@RIEnergy.com; krcastro@RIEnergy.com; CJRooney@RIEnergy.com; joliveira@pplweb.com; TGShields@pplweb.com;	401-784-4263
	nhawk@pplweb.com;	
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; Christy.Hetherington@dpuc.ri.gov; Margaret.l.hogan@dpuc.ri.gov; Paul.roberti@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; William.Owen@energy.ri.gov;	
Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mbedell@riag.ri.gov;	401-274-4400 x 2297
File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Cynthia Wilson-Frias, Esq. Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Kristen.L.Masse@puc.ri.gov;	401-780-2107
Matt Sullivan, Green Development LLC	ms@green-ri.com;	