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September 16, 2025

VIA ELECTRONIC MAIL AND HAND DELIVERY

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

**RE: Docket No. 23-48-EL - FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Reconciliation Filing
Responses to Division Data Requests – Set 1 (Complete Set)**

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”), and for posting to the Public Utilities Commission’s website, attached is the Company’s complete set of responses to the Division of Public Utilities and Carriers’ First Set of Data Requests in the above-referenced matter.

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

Sincerely,

A handwritten signature in blue ink, appearing to read "Andrew S. Marcaccio".

Andrew S. Marcaccio

Enclosures

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

Division 1-1

Request:

Provide the projects and detailed pre-construction costs totaling \$1.0 million that the Company removed from the FY 2025 ISR Fourth Quarter report (Wiesner testimony, p. 6). Expand on how and why the Company plans to advance the projects separate from the ISR spending.

Response:

Please see Attachment Division 1-1 for the projects and detailed pre-construction costs totaling \$1.03 million that the Company removed from the Fiscal Year ("FY") 2025 Electric Infrastructure, Safety and Reliability ("ISR") Plan spend. As indicated in Company witness Eric Wiesner's testimony, the Company anticipates advancing the projects outside of the ISR process.

In general, the Company considers system, regulatory, operational, and financial factors when determining whether to advance capital projects. The Company evaluates safety and reliability factors first and foremost. After evaluating these factors, relying on the expertise and experience of Company personnel, the Company determined that it was necessary to advance the projects identified in Attachment DIV 1-1, for which the Company incurred pre-construction costs totaling \$1.03 million and which were part of the FY 2025 Electric ISR Plan approved budget, separate from the ISR cost recovery mechanism.

First, from a system standpoint, the Company evaluates whether an investment is reasonably needed to maintain safe and reliable distribution service over the short and long term. This analysis also takes into consideration the Company's long-term plans, any applicable mandates, and the Company's responsibility to make investments it deems necessary and prudent to its system, regardless of the availability of the ISR cost recovery mechanism. If the Company finds that an investment is reasonably needed, it proposes that investment in the ISR plan, taking into account customer affordability and other circumstances. In this case, the Company determined that the pre-construction costs and associated projects satisfy the ISR standard as being reasonably needed to maintain safe and reliable distribution service over the short and long term; however, because of ISR plan budget constraints, the Company determined it would need to advance these projects separate from the ISR plan process. More specifically, in reviewing its FY 2026 investment plan, the Company determined that the investments reasonably needed to maintain safety and reliability exceeded the approved FY 2026 ISR budget and that it would have to continue constructing these investments and seek recovery for them via a mechanism other than the ISR. The Company intends to seek cost recovery through a base distribution rate case.

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Second, from a regulatory perspective, the Company appreciates the robust ISR plan process, which includes consultation with the Division of Public Utilities and Carriers (“Division”), filing of the Company’s proposed plan with the Public Utilities Commission (“PUC”), rounds of discovery, an evidentiary hearing, and ultimately approval of an ISR plan budget by the PUC. Each fiscal year, the Company executes the ISR plan in a prudent manner and in an effort to align spending with the approved ISR plan budget. In this case, the pre-construction costs totaling \$1.03 million that the Company removed from the FY 2025 ISR plan spend are tied to projects that will be constructed in future fiscal years. At the time the PUC approved the FY 2025 Electric ISR Plan budget, the Company anticipated investing in the projects tied to these pre-construction costs as part of subsequent ISR plan budgets. This approach changed following the FY 2026 Electric ISR Plan Order, which resulted in a lower ISR plan budget than the Company proposed with Division concurrence. After an internal review, the Company removed certain projects from its FY 2026 electric ISR investment plan to align with the approved FY 2026 ISR plan budget. The projects removed from the FY 2026 ISR investment plan included the projects tied to the \$1.03 million of pre-construction costs identified in Attachment DIV 1-1. Because the Company removed the construction of those projects from the FY 2026 Electric ISR Plan and intends to seek recovery for them in a future base rate case, it also removed the \$1.03 million in pre-construction costs for those projects from the FY 2025 ISR plan spend. Removing those projects from the ISR did not result in the need to remove any dollars from the FY 2025 capital additions total as these projects were not in-service as of the end of FY2025. Of note, the majority of the \$1.03 million in costs removed from the FY 2025 ISR spending are associated with the Phillipsdale substation project which was among a list of projects the PUC ordered be removed from the FY 2026 ISR budget. The Company recognizes that the PUC’s decision did not preclude continued spending on the project nor was it a determination of whether the project would become eligible for cost recovery, whether through the ISR or a future base rate case, in subsequent years.

Third, operationally, in some instances, pausing a project may result in cost inefficiencies such as having to de-mobilize and re-mobilize once the project restarts, inflationary concerns, and engineering change orders. In this case, the pre-construction costs have been incurred, and the Company believes it is more efficient and cost effective to continue to advance the associated projects. With respect to the projects set forth in Attachment DIV 1-1, the Company concluded that continuing to move forward with the projects – even though cost recovery may not, or would not, be available through the ISR cost recovery mechanism – was the most cost efficient and expeditious way to complete these projects and meet the system needs.

Finally, from a financial standpoint, the Company considers its access to capital, interest rates, return on investment, and ability to recover through rates. In this case, the Company balanced the

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need to complete the capital projects in the nearer term with its ability to fund the pre-construction costs and associated projects and determined that it is necessary to take the financial risk to advance the work separate from the ISR plan process and seek cost recovery through a base distribution rate case – even though that results in a risk of disallowance or regulatory lag on recovery of the costs for these projects.

	(a)	(b)	(c)	(d)
	Spending Rationale and Category	ISR Grouping	FY 2025 Budget (\$'000s)	FY 2025 Actuals (\$'000s)
(1)			<u>Asset Condition</u>	
(2)		Div St#61 T1 T2 Replacement	500	59
(3)		Phillipsdale Substation D Line	100	78
(4)		Substation Spare Transformers	540	4
(5)	Total Asset Condition		1,140	141
(6)	<u>System Capacity & Performance</u>			
(7)		Staples #112 Reliability 112W43	340	14
(8)		Staples #112 Reliability 112W44	340	86
(9)	Total System Capacity & Performance		680	100
(10)	Consolidated Soft Budget Limit		1,820	241
(11)	<u>Separately Tracked Major Projects</u>			
(12)	Asset Condition	Phillipsdale Substation	100	792
(13)	Total Separately Tracked Major Projects		100	792
(14)	Total Capital Spending		3,060	1,033

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Division 1-2
DG & DER

Request:

How much of the \$2.6 million underspend for DG was attributable to the correction of a prior year entry for duplicative material costs?

Response:

Actual FY 2025 capital spending related to Distributed Generation projects was a *credit* of (\$1,646,717), \$2,646,717 under the budget of \$1,000,000. The credit was driven by the reversal of material costs that had been recorded twice in the previous year. Total material costs reversed were \$2,540,361.

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Division 1-3
DG & DER

Request:

What is the \$2,370 investment for Strategic DER and why is it considered non-discretionary?

Response:

The Strategic DER Investments capital spending of \$2,370 on Table 5, Line 10 of the FY 2025 Electric ISR Annual Reconciliation relates to tree trimming charges for Project #C086892 - Strategic DER Advancement-Chopmist. This project was designated as a non-discretionary project in the FY 2021 ISR. The work was performed in FY 2024 (October through November 2023) and bills were received in FY 2025.

Division 1-4
New Business

Request:

Are new business increases in the actual spending levels driven by infrastructure cost or the volume of work?

Response:

The Company has experienced increases in customer driven work requests year over year through 2025 to present. Based on the increased customer-initiated work, spending levels have increased based on the increased volume as they are directly proportional.

Lastly, inflation and escalation have substantially increased in the past few years directly stemming back to the COVID-19 pandemic and resulting impact to higher cost of materials and manufacturing throughout the state. Costs of materials have significantly increased in pricing impacting project costs.

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Division 1-5
New Business

Request:

Has the Company revised internal design or construction guidelines for new connections?

Response:

The Company has not revised internal design or construction guidelines for new connections.

Division 1-6
New Business

Request:

How does the Company monitor emerging work to prepare for new connections? Has the Company explored methods to improve forecasting such as coordinating with municipalities to determine upcoming building permits?

Response:

In general, the Company's connection team responds to customer inquiries at the time of the request. There are some cases where a major developer or major construction project may warrant preliminary discussion for planning purposes.

Although the Company meets regularly with municipalities throughout the State to be aligned with upcoming construction planning, there are no forecasting methodologies used. The Company has not explored coordinating further with respect to building permits as the majority of cities and towns have evolved to a newer streamlined portal experience for Rhode Island permit holders.

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Division 1-7
New Business

Request:

Are there any specific large projects contributing to the commercial overspend?

Response:

The following projects had capital spending greater than \$500,000 and contributed to the New Business-Commercial overspend.

	(a)	(b)	(c)
<u>Line Number</u>	<u>Project #</u>	<u>Project Description</u>	<u>FY 2025 Capital Spending</u>
1	C091645	Omni Combined Providence	\$966,186
2	CRI3071	Rogers High School Newport	\$1,717,708
3	CRI3082	Green Development LLC Manufacturing	\$2,107,126
4	COS0011-10030697877	150 Richmond St, Providence - DSVCCOM-Install 3-1/C 500 Cu, 1000	\$1,125,250

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Division 1-8
New Business

Request:

Where are industrial connections/expansions included in the ISR Plan?

Response:

Industrial connections/expansions are included in the Customer Request/Public Requirements spending rationale under a New Business – Commercial grouping in the ISR Plan.

Division 1-9
New Business

Request:

Explain the types of work performed under New Business Commercial. Does work include upgrades to existing services and new connections?

Response:

The following types of work are performed under the Company's New Business Commercial program:

1. New permanent commercial service
2. New temporary commercial service
3. Commercial service upgrade
4. Demolition service request
5. Public requirements (*work required to safely allow or accommodate services requested with respect to connections requests 1 and 2.*)

The connections work referenced above would include both upgrades to existing services and new connections requests.

Division 1-10
New Business

Request:

Please provide the following for projects in the New Business category in executable format for FY 2022 – FY 2025. Explain the basis for connected kW values (e.g. transformer capacity, estimated, etc.):

- a. A list of industrial customer connections with cost, total number of customers, and total kW of newly connected load. Indicate whether the kW connected was new load or incremental (upgrade).
- b. A list of commercial customer connections with cost, total number of customers, and total kW of newly connected load. Indicate whether the kW connected was new load or incremental (upgrade).

The total number of residential customers connected, total costs, and total kW of newly connected load.

Response:

Please note, the Company does not distinguish commercial customers by commercial or industrial in terms of connected kW load profiles. As such the following data sets will represent commercial and residential, with answers to a. and b., provided in the same response.

The Company is unable to further distinguish upgrade load requests versus new load requests. Please see in Attachment DIV 1-10-1, customer segments in terms of all loads for all project types, along with newly requested load requests by customer segment by respective fiscal year. Please see in Attachment DIV 1-10-2, costs per customer segment by respective fiscal year.

Attachment DIV 1-10-1

All Customer Project Types (New, Existing, Upgrades, etc.) Totalized by kW, kWh and Customers by Fiscal Year

(a) Row Labels	(b) FY2022	(c) FY2023	(d) FY2024	(e) FY2025
1 Commercial & Industrial				
2 kW	8,800,112	9,680,889	9,729,064	14,505,833
3 kWh	3,933,363,269	4,424,802,115	4,405,973,263	6,344,802,244
4 No. of Customers	60,461	65,392	67,343	67,926
5 Residential				
6 kW ¹	-	-	-	-
7 kWh	2,658,111,961	3,007,234,121	2,958,456,409	3,044,005,903
8 No. of Customers	428,671	491,504	519,792	520,730
9 Total kW	8,800,454	9,681,052	9,729,181	14,505,864
10 Total kWh	6,591,475,230	7,432,036,236	7,364,429,672	9,388,808,147
11 Total Customers	489,132	556,896	587,135	588,656

12

13 New Customers Totalized by kW, kWh, and Fiscal Year

14 Row Labels	FY2022	FY2023	FY2024	FY2025
15 Commercial & Industrial				
16 kW	Note ²	183,831	201,837	190,022
17 kWh		93,728,511	92,358,335	87,352,283
18 No. of Customers		6,255	6,515	6,029
19 Residential				
20 kW ¹		-	-	-
21 kWh		181,199,035	179,084,492	179,864,067
22 No. of Customers		74,114	77,884	74,143
23 Total kW		183,831	201,873	190,030
24 Total kWh		274,927,546	271,442,827	267,216,350
25 Total Customers		80,369	84,399	80,172

26

27 Increase FY over FY

28

29 Row Labels	FY2022	FY2023	FY2024	FY2025
30 Increase kW	Note ²	1.9%	2.1%	1.3%
31 Increase kWh		2.1%	2.1%	1.4%
32 Customers Increase		9.6%	9.7%	8.9%

kW¹ = Residential customers are not metered on demand-based rates, as such kWh are reflective of all Residential loads.

Note² = New Customer types reflecting the FY2022 (4/1/21 through 3/31/22) period requires data from National Grid. The Company will supplement this response upon receipt and review of the data.

Attachment DIV 1-10-2

New Business Project Related Costs Totalized

	(a)	(b)	(c)	(d)	(e)
Row Labels	FY2022	FY2023	FY2024	FY2025	
1 Commercial & Industrial					
2 Total Costs (CapEx)	8,325,442	10,379,162	10,814,991	18,303,882	
3 Residential					
4 Total Costs (CapEx)	4,691,058	7,695,233	7,325,715	8,723,321	
5 Total Costs (Combined)	13,016,500	18,074,395	18,140,706	27,027,203	

Note = Supporting documentation is being shared under separate cover directly with the Division. The Company will file supporting documentation with the PUC after consultation with the Division.

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Division 1-11
New Business

Request:

Provide the number of customer accounts by class with associated kW load that closed accounts in FY 2022 – FY 2025.

Response:

Please see Attachment Division 1-11.

Attachment DIV 1-11

	(a)	(b)	(c)	(d)	(e)
	YEAR	CLASS	ACCOUNTS_CLOSED	KW	KWH
1	2022	LARGE C&I	102	300,235	125,102,571
2	2023	LARGE C&I	91	248,597	99,935,432
3	2024	LARGE C&I	63	87,501	37,500,017
4	2025	LARGE C&I	25	4,182	703,000
	YEAR	CLASS	ACCOUNTS_CLOSED	KW	KWH
5	2022	MEDIUM C&I	1,326	474,341	147,932,439
6	2023	MEDIUM C&I	1,229	356,027	107,294,419
7	2024	MEDIUM C&I	860	177,474	55,059,934
8	2025	MEDIUM C&I	426	22,300	5,745,518
	YEAR	CLASS	ACCOUNTS_CLOSED	KW	KWH
9	2022	SMALL C&I	12,542	93,056	133,733,776
10	2023	SMALL C&I	12,015	60,233	90,824,524
11	2024	SMALL C&I	8,790	9,047	53,296,581
12	2025	SMALL C&I	3,797	278	8,221,243
	YEAR	CLASS	ACCOUNTS_CLOSED	KW	KWH
13	2022	RESIDENTIAL	132,800	302	607,573,822
14	2023	RESIDENTIAL	142,099	94	495,230,306
15	2024	RESIDENTIAL	108,397	0	309,322,210
16	2025	RESIDENTIAL	48,780	0	62,889,877
	YEAR	CLASS	ACCOUNTS_CLOSED	KW	KWH
17	2022	LOW INCOME RESI	11,450	0	52,540,796
18	2023	LOW INCOME RESI	10,908	0	37,310,410
19	2024	LOW INCOME RESI	6,502	0	17,319,952
20	2025	LOW INCOME RESI	1,493	0	1,887,528

Division 1-12
(Distribution) Transformers and Related Equipment

Request:

Provide an update on the root cause of the transformer overspend (\$17.5 million against \$8 million budget).

Response:

There are multiple root causes for the overspend. However, the reported overspend of \$17.5 million was inaccurate and should have been reported as \$14.9 million.

Root Cause 1:

When the Company transitioned to PPL Corporation (“PPL”) systems in August 2024, there was a change in inventory management philosophy to start tracking all materials located at Rhode Island Energy Service Centers. This change allows the Company to have greater control, visibility, and ability to minimize inventory on hand. As part of this change, material that was currently on hand at the Service Centers needed to be added to inventory in the Company’s system. During this process, as part of the accounting, the “NEC Suspense” account was credited and the “transformer blanket” account was debited. This created an additional \$2.6 million in charges to the transformer blanket for materials that already had been received into service. Accordingly, the Company is now removing that \$2.6 million. The Company has since validated all other transactions have appropriately been credited and debited to the correct accounts and can confirm this was a one-off issue.

Root Cause 2:

During the COVID-19 pandemic, many manufacturers’ lead times increased up to two to three times. In FY 2025, suppliers had stabilized closer to levels of lead times prior to COVID-19, which meant more material was being delivered in FY2025 that the Company had not expected to arrive until FY 2026 or later. Also, old purchase orders from 2022 were still being delivered in FY 2025. Purchase orders that arrived in FY 2025 with an expected delivery date of a different FY increased the spending on the transformer blanket by \$2 million.

Root Cause 3:

As the Company officially integrated into parent company PPL, accounting philosophies were adjusted to align with PPL practices. While doing a review of stores clearing, the Company’s accounting team identified that the stores clearing rate of 16 percent that was being used from April through November was too low. An adjustment was made to increase the stores clearing rate to 30 percent, which led to an increase of \$1.6 million in spending on the transformer blanket.

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Root Cause 4:

Under the Transition Service Agreement, National Grid USA Service Company, Inc. (“National Grid”) was required to provide the Company with a fair share of material to not disrupt normal operations. The conditions of this agreement were that whatever percentage of material used by the Company over the past 10 years, National Grid had to honor. For example, if 100 units of a specific material were used, 70 units by the Company and 30 units by National Grid affiliated entities (other than the Company), then National Grid had to provide the Company with 70 percent of the inventory they had on hand and on order. The fact the this formula covered so many historical years could have caused some excess inventory to be purchased by the Company.

Division 1-13
(Distribution) Transformers and Related Equipment

Request:

Is ISR Plan spend incurred at the time a distribution transformer purchase order is placed, at the time the invoice is paid, or other?

Response:

ISR Plan spend is incurred at the time a distribution transformer is received.

Division 1-14
(Distribution) Transformers and Related Equipment

Request:

In FY24 Reconciliation DIV 1-7, RIE stated that “Transformers are pre-capitalized assets and are placed into service when purchased.” What constitutes “purchased”? Is this the same as delivered and received?

Response:

For the Company, “purchased” is the same as delivered and received.

Division 1-15
(Distribution) Transformers and Related Equipment

Request:

Are all equipment purchases in the Transformers and Related Equipment category treated the same in terms of incurring spend under the ISR Plan versus placed in service?

Response:

Yes.

Division 1-16
(Distribution) Transformers and Related Equipment

Request:

In executable format, please complete the following table for each type of equipment purchase in the Non-Discretionary Transformers and Related Equipment category. Provide data for FY 2023, FY 2024, FY 2025, and FY 2026 proposed:

ISR Plan Non-Discretionary: Transformer & Equipment Category

Equipment Type	FY 2022 Starting Inventory	FY23 Purchased		FY23 Received		FY23 Inventory Reduction	FY23 Ending Inventory
		# Units	Cost	# Units	Cost	#	#
Overhead Transf.							
Underground Transf.							
Voltage Regulators							
Capacitors							
Etc.							

Response:

Please refer to the Excel version of Attachment Division 1-16 for data. Below is commentary around the file as well as a description of each column for reference and understanding.

All data for FY 2022, FY 2023, and the quantities received for FY 2024 were provided by National Grid. FY 2025 data was pulled directly from the Company’s system. FY 2024 and FY 2025 ending year data include materials that were transferred from National Grid to Rhode Island Energy in those respective fiscal years. No costs are associated with these transfers because there is not a clear way to differentiate in which fiscal year the material was received.

Below is a description of each column in each of the three tabs.

For FY 2023 tab:

Column (a) – Equipment Type – The category of the equipment that is on the transformer blanket.

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Column (b) – FY 2022 Starting Inventory – Inventory that was held by National Grid in their Sutton, MA yard that was specifically designated for Rhode Island Energy.

Column (c) – FY23 Purchased # – The number of units that National Grid purchased for Rhode Island Energy.

Column (d) – FY23 Purchased Cost – The cost of the total number of units purchased by National Grid for Rhode Island Energy.

Column (e) – FY23 Received # – The number of units systematically received by National Grid for Rhode Island Energy.

Column (f) – FY23 Received Cost – The cost of the number of units systematically received by National Grid for Rhode Island Energy.

For FY 2024 tab:

Column (a) – Equipment Type – The category of the equipment that is on the transformer blanket.

Column (b) – FY24 Purchased # – The number of units that National Grid purchased for Rhode Island Energy.

Column (c) – FY24 Purchased Cost – The cost of the total number of units purchased by National Grid for Rhode Island Energy.

Column (d) – FY24 Received # – The number of units systematically received by National Grid for Rhode Island Energy.

Column (e) – FY24 Received Cost – The cost of the number of units systematically received by National Grid for Rhode Island Energy.

Column (f) – FY24 Received # – Additional units received by National Grid for Rhode Island Energy in FY 2024. Data was provided by National Grid and it is unclear why this is broken out separately from information in Column (i) with no costs.

Column (g) – FY24 Transferred – The number of units that were transferred from National Grid to Rhode Island Energy.

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Column (h) – FY24 Inventory Reduction – The number of units installed during the fiscal year. This number was calculated by subtracting Column (i) by the sum of Column (d), Column (f), and Column (g). It is unknown what the starting balance of FY 2024 was.

Column (i) – FY 2024 Ending – This number represents what was on hand in Rhode Island Energy's inventory on 3/31/24.

For FY 2025 tab:

Column (a) – Equipment Type – The category of the equipment that is on the transformer blanket.

Column (b) – FY25 Starting Inventory – The number of units on hand on 4/1/24.

Column (c) – FY25 Purchased # – The number of units that National Grid purchased for Rhode Island Energy.

Column (d) – FY25 Purchased Cost – The cost of the total number of units purchased by National Grid for Rhode Island Energy.

Column (e) – FY25 Received # – The number of units systematically received by National Grid for Rhode Island Energy.

Column (f) – FY25 Received Cost – The cost of the number of units systematically received by National Grid for Rhode Island Energy.

Column (g) – FY25 Transferred – The number of units that were transferred from National Grid to Rhode Island Energy.

Column (h) – FY25 Inventory Add – The number of units that were at Service Centers that were uploaded into Rhode Island Energy's inventory.

Column (i) – FY25 Inventory Reduction – The number of units installed during the FY. This number was calculated by subtracting Column (j) by the sum of Column (b), Column (f), Column (g), and Column (h).

Column (j) – FY 2025 Ending – This number represents what was on hand in Rhode Island Energy's inventory on 3/31/25.

Division 1-17
(Distribution) Transformers and Related Equipment

Request:

In executable format, please provide the following information for the Non-Discretionary Transformers and Related Equipment category:

	FY21	FY22	FY23	FY24	FY25	FY26 Proposed
ISR Spend						
ISR Plant in Service						

Response:

Please see Excel file Attachment Division 1-17.

Line 2 and Line 5 show adjustments to the filed FY 2025 Annual Reconciliation capital spending and plant in service amounts. This adjustment relates to an inventory receipt that was duplicated. Please see the Company’s response to Division 1-12 for more information.

Attachment DIV 1-17

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line Number		FY 2021	FY 2022	FY2023	FY 2024	FY 2025	FY 2026 Budget
1	ISR Capital Spending As Originally Filed	\$4,199,427	\$5,631,462	\$5,761,392	\$10,921,860	\$17,543,411	\$8,000,000
2	Adjustment					(\$2,599,375)	
3	Adjusted ISR Capital Spending	\$4,199,427	\$5,631,462	\$5,761,392	\$10,921,860	\$14,944,036	\$8,000,000
4	ISR Plant in Service as Originally Filed	\$5,206,019	\$5,691,579	\$5,619,684	\$11,096,737	\$17,741,828	\$8,000,000
5	Adjustment					(\$2,599,375)	
6	Adjusted ISR Plant in Service	\$5,206,019	\$5,691,579	\$5,619,684	\$11,096,737	\$15,142,453	\$8,000,000

Division 1-18
(Distribution) Transformers and Related Equipment

Request:

When does the Company purchase distribution transformers for conversions identified in Area Studies? Is spend included under a separate project or within the non-discretionary transformer category? Are those transformers pre-capitalized and placed in service when purchased, received, or some other method?

Response:

Conversions identified in Area Studies use distribution transformers purchased in the same manner as non-conversion work. Spend is not included under a separate project and is within the non-discretionary transformer category. The transformers are pre-capitalized and placed in service when received.

Division 1-19
(Distribution) Transformers and Related Equipment

Request:

RIE previously forecasted \$12M annually for FY 2026-FY 2030 but has budgeted \$8M in FY26. Explain the basis for the FY26 forecast.

Response:

The Company established its FY 2026 budget based on a revised forecast that incorporates known outstanding transformer orders and a demand plan that incorporates estimated usage, unit pricing and inventory as of September 2024. The demand plan is updated quarterly.

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Division 1-20
Public Requirements

Request:

The Company indicates that \$1.5 million underspend was attributable to lower public requirements work but offset by increased billing for joint owned pole replacements (Attachment 1, p. 2). Please explain how the joint owned billing, where the Company bills the joint owner for pole replacement and receives payment, is contributing to an increase in Public Requirements cost.

Response:

Public and Regulatory Requirement capital spending was under budget for fiscal year (“FY”) 2025. Increased billing for joint-owned pole replacements contributed to the underspend.

The billing for all joint-owned pole replacements is recorded in one project and included on the Public and Regulatory Requirements line on Table 5 – Customer Request/Public Requirement Capital Spending in the FY 2025 Annual Reconciliation filing, Attachment EJW-1, Page 8 of 20.

Billing for joint-owned pole replacements reduces capital spending. As shown on the table below, capital spending on public requirement work, including Rhode Island Department of Transportation projects, was less than budgeted. The credit associated with joint-owned pole billing was greater than budgeted and exceeded the capital spending on public requirement work.

	(a)	(b)	(c)
Line Number	<u>Description</u>	<u>FY 2025 Budget</u>	<u>FY 2025 Actuals</u>
1	Public Requirements Blanket	\$2,124,200	\$1,219,212
2	Reserve for Public Requirements Projects	2,815,800	--
3	Public Requirements – Specific Projects	--	755,990
4	Joint-owned Pole Billing	<u>(1,800,000)</u>	<u>(3,477,815)</u>
5	Public & Regulatory Requirement (Table 5, Line 8)	<u>\$3,140,000</u>	<u>(\$1,502,614)</u>

Division 1-21
Public Requirements

Request:

Provide the annual number of joint owned poles installed and replaced by the Company, the actual pole installation or replacement cost incurred by the Company, amount billed to joint owner, and amounts received from the joint owner for FY 2022 through FY 2025.

Response:

Please note that, although the completion of the field activity occurs in a specific fiscal year, the process of issuing an invoice to the joint owner, Verizon, and then receiving payment from Verizon may occur in one to two fiscal years after the field work is completed. The Company has structured this response into multiple sections and supporting tables to reflect that dynamic. Please also note, not all data for historical years was readily available and required a request to National Grid. The Company will supplement this response once it receives the historical data from National Grid.

Number of Joint Poles Installed and Replaced:

Below is a count of the joint owned poles installed and replaced by the Company, summed by the year the field activity occurred. Please note, this activity occurs across a wide array of programs, so it is a labor-intensive process to identify and isolate the associated costs:

Table A				
	FY2022	FY2023	FY2024	FY2025
1	1,444	1,557	1,511*	TBD*

*The FY2024 pole count is based on invoicing the Company has completed, which covers field activity from April 2023 through February 2024 (11 of 12 months for FY2024). The count for FY2025 is To Be Determined (TBD) because the Company has not yet completed the analysis and resulting invoicing to determine a work on joint owned poles total count.

Division 1-21, page 2

Actual Pole Installation or Replacement Cost Incurred by the Company:

As mentioned above, the costs associated with the installation and placement of joint owned poles occurs across a wide array of programs, and it is a labor-intensive process to identify and isolate the costs on a pole-by-pole or workorder-by-workorder basis (which would be needed to fully answer this question). The Company, however, has performed an analysis to determine a count of joint poles that was used to complete the joint pole billing to Verizon. The Company utilized an average rate of \$1,240 per pole (or approximately 50% of the total cost of installing the wood pole in the ground) to bill Verizon. The table below has been created to provide an approximate cost incurred by the Company for joint pole installation and replacement.

Table B				
	FY2022	FY2023	FY2024	FY2025
1	\$3,581,120	\$3,861,360	\$3,747,280*	TBD

*The FY2024 total is based on the number of joint owned poles the Company has invoiced to Verizon, which covers field activity from April 2023 through February 2024 (11 of 12 months for FY2024). The total for FY2025 is To Be Determined (TBD) as the Company has not yet completed the analysis and resulting invoicing to determine a work on joint owned poles total count and resulting spend.

Amounts Billed to Joint Owner:

The Company generates invoices for joint owned pole field activity that are created based on the month the field activity occurred. Then, at a later date, the Company sends the invoices out to Verizon on a rolling basis to request payment. In FY2025, the Company sent invoices to Verizon associated with 14 months of field activity totaling \$2,605,240.

Table C – Summed by FY When Invoices Sent					
		FY2022	FY2023	FY2024	FY2025
1	Invoices Total	\$1,598,360*	\$240,560	\$1,004,400	\$2,605,240
2	Invoice Count	10	2	8	14

*FY2022 included invoicing for field activity back to March 2021 (FY2021).

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Amounts Received from the Joint Owner:

The table below lists the totals received from (invoice paid by) Verizon per fiscal year. Please note, the Company has currently answered this question with all available Rhode Island Energy data. Additional historical information will be needed from National Grid. The Company will supplement this response once the information is received and reviewed.

Table D – Summed by FY When Payment Received						
		FY2022	FY2023	FY2024 ³	FY2025	FY2026 ⁴
1	Invoices Total	Note 1	Note 2	\$1,016,800	\$1,996,400	\$737,800
2	Invoice Count	Note 1	Note 2	8	10	5

Note 1: The Company was unable to fully validate Verizon’s payment activity for this period. Based on the dates when National Grid sent invoices to Verizon and assuming Verizon paid the invoices in a timely manner, it appears the FY2022 total is \$1,248,680 comprised of 7 invoices, but a data request to National Grid is necessary to valid these amounts.

Note 2: The Company was unable to fully validate Verizon’s payment activity for this period. Based on the dates when National Grid sent invoices to Verizon and assuming Verizon paid the invoices in a timely manner, it appears the FY2023 total is \$448,880 comprised of 4 invoices, but a data request to National Grid is necessary to valid these amounts.

Note 3: Includes invoice for March 2022 (FY2022 activity) in the amount of \$155,000. The Company was unable to confirm Verizon payment date, but for this analysis, the Company assumed it was also paid in FY2024 as it was sent to Verizon along with the April FY2023 invoice; that April invoice was paid on 8/22/2023, in FY2024.

Note 4: In FY2026, the Company has received payments from Verizon related to field activity through December 2023 (FY2024). As of the approximate date of this response, the Company has invoiced Verizon through the field activity month of February 2024 (FY2024).

Division 1-22
Public Requirements

Request:

Provide the annual number of joint owned poles removed by the joint owner, billed to the Company, and paid by the Company for FY 2022-FY 2025.

Response:

Table A lists the count of joint owned poles removed by the joint owner (Verizon), summed by the fiscal year when the field activity occurred.

Table A: Number of joint owned poles removed by the joint owner By fiscal year of when the field activity occurred.				
	a	b	c	d
	FY2022	FY2023	FY2024	FY2025
1	1,548	1,272	1,636	1,504*

*Note, the total does not include field activity for January 2025 through March 2025 as those amounts have not been billed by Verizon to the Company yet.

Table B lists the totals by fiscal year of the dollar amounts billed by the joint owner (Verizon) and paid by the Company, summed by fiscal year when the invoices were paid. The Company has also included the count of invoices that were paid by fiscal year. Verizon bills the Company \$385 for every pole removal.

Table B: Total \$ billed to the Company and paid by the Company By fiscal year of when the Company paid the invoice.					
		a	b	c	d
		FY2022	FY2023	FY2024	FY2025
1	Invoices Total	\$519,700	\$0	\$486,910	\$832,365*
2	Invoices Count	13	0	12	16

*Note, the Total of Invoices paid in FY2025 includes field activity through April 2024 (FY2025). Additional invoices for field activity through December 2024 (FY2025) have been received and paid in FY2026.

Division 1-23
Public Requirements

Request:

The Company indicates that Cost of Removal was \$3.3 million over budget partly due to the increased number of removal costs associated with joint owned poles (Attachment EJW-1, p. 4). How much of the variance was due to joint owned pole removal costs and why is that work increasing?

Response:

The total removal costs reported in FY2025 associated with joint owned poles was \$1,140,666 versus a budget of \$600,000, which contributed \$540,666 to the over budget variance. That total includes the impact of accrual activity and Company overheads. This over budget variance was not specifically due to an increase in field activity, which is primarily completed by Verizon and periodically billed to the Company. Rather this increase was primarily the result of the Company getting caught up with approving and paying the invoices received from Verizon. In FY2025, the Company paid Verizon for cost of removal invoices associated with 16 months of field activity (field activity occurred between January 2023 and April 2024).

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Division 1-24
Damage Failure

Request:

What is driving the year-over-year increase in Monthly Confirming Work (\$6.7 million in FY 2024 versus \$11.4 million in FY 2025)? Are the increases expected to continue? What is the FY26 budget for Monthly Confirming Work?

Response:

The work identified as Monthly Confirming Work conducted under the Damage/Failure blanket is, by its nature, reactive and non-discretionary. The Company has not identified any specific trend to indicate a reason for the increase in spending in this category from FY 2024 to FY 2025. The Company continues to see spending trend above FY 2024 levels but forecasts lower end of year totals than FY 2025, however it will continue to react as necessary to observed field conditions and make any required repairs. There is no specific budget for Monthly Confirming Work, but it is a sub-category of the Damage/Failure blanket which has a FY 2026 budget of \$12.02 million.

Division 1-25
Asset Condition

Request:

Please provide a list of FY 2025 projects completed in the Asset Replacement Blanket category similar to the format used to report quarterly Damage/Failure capital spending. What criteria or other factors determine whether a project is advanced under the Asset Replacement Blanket versus Damage/Failure?

Response:

The Asset Replacement blanket projects consist of many work orders that are typically standard construction, of short duration, and small cost. There are two projects, one for distribution line work and one for substation work. The table below shows the Asset Replacement Blanket capital spending similar to the format used to report quarterly Damage/Failure.

Line Number	(a)	(b) Fiscal year Ending March 31, 2025		
		(c) D Line Blanket	(d) D Sub Blanket	Total
1	Monthly confirming work	\$4,540,752		\$4,540,752
2	OH & UG Elec Distribution	1,393,889		1,393,889
3	Other	376,530	38,195	414,725
4	Total	\$6,311,172	\$38,195	\$6,349,367

The Company classifies work on equipment as either Damage/Failure or Asset Replacement, depending on the condition and context:

1. Damage/Failure refers to the replacement of an asset that has electrically, structurally, or mechanically failed and is unable to perform its intended function.
2. Asset Replacement applies to an asset that remains functional but requires replacement due to reaching end-of-life, being logistically unsupportable, or showing signs of anticipated near-term failure.

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In some cases, both classifications may apply to the same asset. For example, a cable fault that is resolved with a splice to restore customer service would be categorized as Damage/Failure. However, if conditions encountered during the fault indicate that the cable or a section of it has been degraded, the Company may assess it as "in need of replacement," and initiate an Asset Replacement project.

Division 1-26
Fiber Study

Request:

Provide details for the \$100,000 expenditure for the Fiber Study. Is the study considered complete? What are next steps?

Response:

The Fiber Study is completed. The study identified the necessary communication routes between substations. The routes were then reviewed against current and pending projects to refine the scope. Specifically, routes to stations that will be retired in the near future were eliminated. The Company intends to conduct an economic evaluation of continuing with third party communication systems versus expansion of Company owned fiber lines.

Division 1-27
Other Area Study Projects-Attachment E

Request:

Regarding the new project to relocate a distribution line from under Woonsocket Sub; explain the project and need. Was it identified in the Area Study? If so, why is it new? If not, when was it identified? What is the expected cost and how does the project timeline align with the Nasonville transmission line work?

Response:

The Woonsocket D-line relocation project scope is to rebuild the 26W1 distribution line built under the B23 transmission line in the right of way entering into Nasonville substation with its own set of poles off set from the transmission line structures. The project was not identified in the 2021 North West Rhode Island Area Study. It was identified as a requirement for the new Woonsocket to Nasonville 115kV transmission line construction at the beginning of 2024.

While the B23 and U-170 double circuited transmission line in the 50-foot wide, 0.6-mile long right of way entering into Nasonville substation was being designed, the contracted transmission line design engineers determined that the distribution line underbuilt to the existing B23 pole structures would need to be relocated. The distribution line underbuilt to the existing B23 pole structures must remain energized during these planned B23 transmission line outages to pick up Nasonville substation load, which creates a safety issue for the transmission line work. Therefore, the distribution line needs to be relocated before the B23 and U-170 transmission line construction can commence.

The estimated cost of the Woonsocket D-line relocation project is \$1.375M. It is targeted to be in service by late 2025 or early 2026 before the B23 and U-170 line construction starts.

Division 1-28
Other Area Study Projects-Attachment E

Request:

Attachment E indicates that many projects have delayed engineering and/or procurement resulting in reduced spend. What is causing the engineering delays? What is the Company doing to improve engineering production? Are engineering and procurement delays expected to persist in FY 2026?

Response:

The majority of projects that have delayed engineering are a result of the Company's resequencing of projects associated with ISR Plan budget constraints. The deferral is initiated by an engineering department and is then termed an engineering delay. Because these delays do not arise from deficiency in engineering production, the Company has no plans to improve engineering production to address them. These delays are expected to persist into FY 2026 and beyond.

A few projects are related to actual engineering delays where the specific project required additional analysis. Additional analysis can be required to refine the scope documents for project handoff, further or new issue identification or economic evaluation are required through regulatory discussions or orders, an opportunity arises to gain efficiencies by combining project or programs, the project is held to reconsider a new alternative, and other reasons. The Company currently has no plans to add additional engineering resources for these limited occurrences. However, for projects such as volt-var optimization, where regulatory discussions are leading towards a more labor intensive feeder specific analysis versus the current station level analysis, additional resources may be necessary.

Procurement delays associated with longer manufacturing timelines than previous years are expected to continue into future fiscal years.

Division 1-29
Other Area Study Projects-Attachment E

Request:

Overall, what impact will project delays and deferrals have on FY 2026 ISR Plan and beyond? How will the Company manage the sequence and implementation timeline of project backlogs while also advancing new projects, within budget targets?

Response:

The response to Division 1-28 explains that many of the delays and deferrals are associated with the ISR Plan budget limits. Starting in FY 2025, continuing into FY 2026 and beyond, the Company has responded and aligned to the Commission's concerns regarding customer affordability by sequencing or deferring projects into the future. This is expected to continue.

The Company agrees this has the potential to create a compounding backlog as new projects are identified and new issues emerge. However, it is also recognized that some of the current compounding of project costs is related to the recent coincident completion of many area studies. The Company does not intend to complete area studies coincidentally in the future, which should mitigate some potential backlogs. Aside from emerging work volumes, Rhode Island Energy agrees with the Commission that the electric system needs to be maintained regardless of recovery mechanism. The Company will closely monitor the current budget framework to determine if compounding financial risk assumed by the Company is occurring. The Company will continue to manage the sequence and implementation timeline of projects within ISR budget targets and use other recovery mechanisms as necessary to maintain system reliability and safety.

Division 1-30
Accelerated Projects

Request:

Why was the Crossman Sub D-Line project accelerated? What work was completed in FY 2025 (\$592,000)? Was plant placed in service? What is remaining work?

Response:

The FY 2025 budget for Crossman Sub D-Line was \$350,000 which included design and some construction. The actual cost was \$592,000. This is a minor change in the overall work the Company conducts on a yearly basis, and such changes occur every year and are frequent. The Company will make such changes as a result of resource availability, permitting activities of this project and other projects, equipment availability of this project and other projects, and other work progression details.

The specific work completed was conversion on Moshassuck Ind Highway.

The plant placed in service was approximately \$187,000.

Division 1-31
Spare Transformers and Mobile Substations

Request:

The Company deferred initial payments for substation spare transformers and mobile substations in FY 2025. Explain whether the payments were deferred but not the orders, or are the orders completely delayed? What are the new schedules for both categories? Discuss how this impacts the overall programs and future purchases.

Response:

The orders and payments were delayed due to budgetary reasons. The Company will be purchasing seven (7) transformers in FY 2026 instead of three (3) in FY 2025 and four (4) in FY 2026.

Please see the Company's response PUC 1-2-Supplemental in in this docket for the new payment schedule and delivery dates.

Division 1-32
Spare Transformers and Mobile Substations

Request:

What agreements are in place with National Grid for spare equipment during emergencies and how have lease terms and charges changed after transitioning to PPL ownership? Is the Company pursuing additional alternatives for emergencies?

Response:

There are two agreements between National Grid and the Company related to spare equipment during emergencies. One agreement is for leasing a mobile substation, and the other is for purchasing a spare transformer.

Leasing Mobile Substation:

The Mobile lease agreement terms have been updated since transitioning to PPL ownership in 2022. The original agreement had The Lessee paying the Lessor (a) Logistics Costs, and (b) Logistics Costs plus Depreciation for each day commencing when the assets were delivered on site until the Lessor took control of the equipment again.

The new mobile lease agreement terms have The Lessee paying the Lessor (a) Logistics Costs, (b) Depreciation costs, (c) Associated OM fees, and (d) a Base Cost at the going market rate commencing when the assets are delivered on site until the Lessor takes control of the equipment again.

Purchasing Transformer:

The Spare Transformer purchase agreement, upon the transition to PPL ownership and after the updated June 2024 agreement, provided the seller the option to either sell the spare transformer at either the Net Book Value including costs associated with "load-out costs" and freight chargers or the replacement cost of the spare transformer. No substantial changes have been made to the spare transformer purchase and sale agreement.

When an emergency arises, the Company reviews its own inventory of spare transformers, as well as any transformers assigned to any upcoming capital project, but is not yet installed in the field. If a suitable replacement is not found, the Company reaches out to the other PPL operating companies for similar asset types that could serve the purpose with small modifications, if warranted. If the other PPL operating companies do not have the equipment, the Company

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reaches out to neighboring utilities to see if they are able to sell/lease a replacement to the Company. In addition, the Company also proactively looks out on the open market for used equipment that could serve the need with reliability, risk and cost in mind that best serves its customers.

Division 1-33
Spare Transformers and Mobile Substations

Request:

How many spare substation transformers and mobile substations are on order now (that are not replacing failed units), what are the amounts and timing of remaining payments due, and when is delivery expected?

Response:

As of August 26, 2025, the Company has ordered one of the spare transformers and has ordered none of the Mobile substations.

The Company has ordered the 34.5kV/11.0kV 20 MVA transformer. This is one of the original three to be purchased in FY2025. The cost was \$1.1 million dollars with a delivery date of October of 2026.

The remaining spare transformers from FY2025 will go out for purchase in September of 2025 with deliveries expected in FY2028. The upcoming four spare transformers for FY2026 are being sent out for quotation at the end of Q2 FY2026 for purchase initiation in Q4 of FY2026. For the Mobile substations, the Company expects to order one in each of Q2, Q3, and Q4 of FY2026.

At this point, the Company is expected to pay approximately \$4.0 million dollars for each mobile substation with an expected 3-year delivery timeframe.

Attachment PUC 1-2-Supplemental in this docket contains the updated cost and projections of the spare transformer inventory and purchases. The Company has included Attachment PUC 1-2-Supplemental from its PUC 1-2-Supplemental response for ease of cross reference and has labeled it as Attachment DIV 1-33 included with this response.

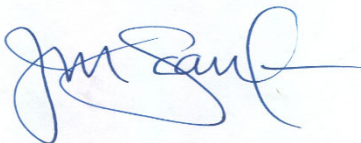
Attachment PUC 1-2-Supplemental

(a)	(b)	Spare Transformer Purchases							(j)	(k)	
Voltage and Rating	Winding Configuration	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total Cost (\$) per Transformer	Est. Delivery Date	
(1)	115-13.2kV 33/44/55 LTC	Delta-Wye		\$1,400,000		\$2,100,000			\$3,500,000	FY28	
(2)	115-13.2kV 33/44/55 LTC	Delta-Wye				\$525,000	\$1,925,000	\$1,050,000	\$3,500,000	FY30	
(3)	115-13.2 24/32/40 LTC	Delta-Wye		\$525,000	\$1,925,000	\$1,050,000			\$3,500,000	FY28	
(4)	115-13.2 24/32/40 LTC	Delta-Wye			\$525,000	\$1,925,000	\$1,050,000		\$3,500,000	FY29	
(5)	115-13.2 24/32/40 LTC	Delta-Wye					\$525,000	\$1,925,000	\$1,050,000	\$3,500,000	FY31
(6)	115-34.5kV 48/64/80	Delta-Wye		\$675,000	\$2,475,000	\$1,350,000			\$4,500,000	FY28	
(7)	115-34.5kV 33/44/55	Wye-Wye					\$525,000	\$1,925,000	\$1,050,000	\$3,500,000	FY31
(8)	115-34.5kV 33/44/55	Delta-Wye					\$525,000	\$1,925,000	\$1,050,000	\$3,500,000	FY31
(9)	115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta					\$525,000	\$1,925,000	\$1,050,000	\$3,500,000	FY31
(10)	115-34.5-13.8 24/32/40 MVA	Wye-Wye			\$525,000	\$1,925,000	\$1,050,000		\$3,500,000	FY29	
(11)	115-23kV 30/40/50	Delta-ZigZag			\$525,000	\$1,925,000	\$1,050,000		\$3,500,000	FY29	
(12)	115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta		\$525,000	\$1,925,000	\$1,050,000			\$3,500,000	FY28	
(13)	69-13.8kV 24/32/40 LTC	Delta-Wye		\$1,200,000		\$1,800,000			\$3,000,000	FY28	
(14)	69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta				\$450,000	\$1,650,000	\$900,000	\$3,000,000	FY30	
(15)	33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye			\$300,000	\$1,100,000	\$600,000		\$2,000,000	FY29	
(16)	34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye			\$150,000	\$550,000	\$300,000		\$1,000,000	FY29	
(17)	34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag								Removed	
(18)	34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta		\$440,000	\$660,000				\$1,100,000	FY27	
(19)	23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye		\$225,000	\$825,000	\$450,000			\$1,500,000	FY28	
(20)	23-11.5kV 10/12.5MVA	ZigZag-Delta				\$150,000	\$550,000	\$300,000	\$1,000,000	FY30	
(21)	22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye				\$150,000	\$550,000	\$300,000	\$1,000,000	FY30	
	Count	0	7	5	4	4			20		
(22)	8 transformers highlighted in DIV 3-16, Docket No. 24-54-EL	Total Material Cost (\$) per FY	\$0	\$4,990,000	\$9,835,000	\$16,500,000	\$10,825,000	\$10,250,000	\$4,200,000	\$56,600,000	
(23)		Total Engineering Cost (\$) per FY	\$0	\$130,000	\$175,000	\$45,000	\$25,000	\$0	\$0	\$375,000	
(24)		Total Construction Cost (\$) per FY	\$0	\$0	\$1,200,000	\$978,570	\$0	\$0	\$0	\$2,178,570	
(25)		Total Overall Cost (\$) per FY	\$0	\$5,120,000	\$11,210,000	\$17,523,570	\$10,850,000	\$10,250,000	\$4,200,000	\$59,153,570	

Certificate of Service

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

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



Joanne M. Scanlon

September 16, 2025
Date

**Docket No. 23-48-EL – RI Energy’s Electric ISR Plan FY 2025
Service List as of 8/21/2025**

Name/Address	E-mail Distribution	Phone
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