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Rhode Island Energy™
a PPL company

February 9, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-37-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project
Tiverton Project
Responses to Division Data Requests – Set 4 (Complete Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's complete set of responses to the Division of Public Utilities and Carriers' ("Division's") Fourth Set of Data Requests concerning the Tiverton Project in the above-referenced docket.

This transmittal contains the Company's response to data request Division 4-1, which was the remaining response in this set.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 23-37-EL Service List

Division 4-1

Request:

On page 19 of the testimony in this docket, the Company states: "The Company is estimating that the work will be completed and placed in service during FY 2025, but would have been completed and placed in service in FY 2029 without the DG project. Since the Company would be paying Green at the time the investment was placed in service in FY 2025, the Company proposes that it would begin recovering depreciation and return from distribution customers in FY 2025 through the ISR plan revenue requirement."

In Docket No. 5077, National Grid provided responses dated February 21, 2021 to PUC's questions (dated February 10, 2021). In its response related to a hypothetical situation in which an interconnection requires a $500k system modification coupled with a planned $200k system improvement to take place 5 years after the interconnection, the Company replied: "The DG site would pay $500k - $200k + Acceleration Cost. The Acceleration Cost is the time value of money on advancing the $200k project to the current year."

Does the Company propose to apply an adjustment to the amount that goes into rate base to account for the time value of money that the distribution customers have paid in advance of the time that the system improvements would have been implemented in the absence of the interconnection of the interconnection project?

Response:

The Company's proposal in this docket does not include an adjustment to the amount charged to base distribution customers for the time value of money for the accelerated system improvements. As described in the response to DIV 4-4, a system issue may have benefits to being accelerated and implemented earlier; however, the Company must take into account several factors in determining the need date in studies and ISR plans such as execution schedules and affordability to customers so the date that a system issue is included in ISR plans is not the earliest date that the investment is needed.

That being said, the Company would not be opposed to an alternative method similar to what was described in National Grid's response to PUC questions in Docket No. 5077 where the amount reimbursed to DG customers would be reduced by an acceleration cost. If that was approved by the PUC, the amount of the acceleration cost borne by DG customers would reduce the amount included in rate base for recovery from base distribution customers.

Prepared by or under the supervision of: Stephanie Briggs

Division 4-2

Request:

Will distribution customers be compensated for amounts that they pay in advance if the accelerated System Improvements are subsequently determined not to be needed when the initial ISR plan anticipated these projects? If so, please explain how they will be compensated. If not, please explain why not.

Response:

In addition to waiting until the project is placed into service and the final audit of costs are complete, the Company does not intend to charge distribution customers until a ruling has been made by the Public Utilities Commission ("PUC") on the Company's Petition for Acceleration. In the Company's Petition, the Company requested April 1, 2024 as the date to begin charging customers. The Company is no longer seeking that date. It is the Company's position that once a PUC ruling is made, the issue of need will have been resolved through that ruling and will not be revisited again in subsequent fiscal years.

The Company has presented substantial amounts of information showing the need for the project and that the need continues to exist. The Company believes a determination that the project is not needed would be contrary to the analysis that has been performed by the Company and has been presented through the Tiverton Area Study and discovery in this docket. Specifically, the Company's response to DIV 1-2, 1-9, 2-3, 2-8, 2-9, and 2-10 contain information showing a current and continuing need.

Division 4-3

Request:

To the extent that the DG customer uses the distribution system to deliver its power output back to the Company, is the capacity available to the distribution customers reduced? If so, has there been any recognition of this reduced capacity in the calculation of the amount of the reimbursement to the DG customer?

Response:

The DG customer is a generator and for purposes of this response, uses 'reverse' capacity. For purposes of this response, the distribution load customers can be considered to use 'forward' capacity. To the extent the generation is timed with the load, the generation offsets the load and enables more forward capacity upstream of the generator. There is no reduced capacity and as a result, no calculated change to the reimbursement to the DG customer.

Division 4-4

Request:

On page 6 of the Company's testimony, it states: "This Petition will impact ratepayers in two beneficial ways; one is the benefit of the accelerated solution, and the other is that the cost to the ratepayers will be a discounted amount from what they otherwise would have had to pay given the depreciation or "acceleration" fee that is borne by the DG customer." If the solution was originally determined to be required in 2029, how is accelerating it 4 years to 2025 a benefit, and if the system is therefore depreciated by 4 years when it has not been determined to be needed by the Company, how is a system improvement that has experienced the wear and tear of 4 years of depreciation a benefit?

Response:

The customers will receive the benefit of the equipment, specifically its contingency capability and reliability impacts. Often when the Company identifies system issues, it must take into account a reasonable execution schedule when proposing the schedule for the recommended project. The identification of the issues plus the reasonable schedule establishes the need date. There are many cases where project acceleration can still provide benefits ahead of the need date.

Division 4-5

Request:

The Company's response to PUC 1-4 in this docket, provided the following information.

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Scenario (a) *	$675,791	$1,333,642	$1,298,642	$1,264,896	$1,232,144
Scenario (b) **	$ 0	$ 0	$ 0	$ 0	$675,791
Difference	$675,791	$1,333,642	$1,298,642	$1,264,896	$556,354

* Assumes included in ISR beginning FY 2025
** Assumes included in ISR beginning FY 2029

Please provide the basis for each year's revenue requirement calculation, including: the amount of capital addition to rate base, depreciation, tax, operation & maintenance expense. Also, please provide all assumptions including: depreciation rate, tax rate, cost of capital, any inflation assumptions, and any other assumptions needed to derive these figures.

Response:

For purposes of the response to PUC 1-4, the Company used the FY 2024 Electric ISR revenue requirement model, including all assumptions in that model, to calculate the illustrative revenue requirement as it was the most recent model at the time of the filing of this petition. At the time that these investments are actually included in the ISR for recovery from customers, the Company would apply the current rates at that time.

FY 2024 Electric ISR Revenue Requirement model assumptions used in both scenarios:

Model assumptions:		
Composite Book Depreciation Rate		3.16%
MACRS Tax Rate		20 Year
Capital Repairs Deduction Rate		8.51%
Effective Federal Tax Rate		21.0%
Pre-Tax Rate of Return		8.23%
Capital Addition		$ 13,038,604

Prepared by or under the supervision of: Stephanie Briggs

Division 4-5, page 2

Please see the following tables which provide the basis and breakdown of the revenue requirement for each year presented in PUC 1-4 for scenario (a) and scenario (b):

Scenario (a)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Capital addition to rate base	$ 13,038,604	$ 0	$ 0	$ 0	$ 0
Accumulated Deferred Taxes	($ 293,855)	($ 408,499)	($ 509,566)	($ 598,107)	($ 675,025)
Average Rate Base	$ 6,296,179	$ 12,157,260	$ 11,740,963	$ 11,337,192	$ 10,945,044
Revenue Requirement:					
Book Depreciation Expense	$ 157,615	$ 315,230	$ 315,230	$ 315,230	$ 315,230
O&M expense	$ 0	$ 0	$ 0	$ 0	$ 0
Return and taxes	$ 518,176	$ 1,018,232	$ 983,412	$ 949,666	$ 916,914
Total Revenue Requirement	$ 675,791	$ 1,333,462	$ 1,298,642	$ 1,264,896	$ 1,232,144

Scenario (b)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Capital addition to rate base	$ 0	$ 0	$ 0	$ 0	$ 13,038,604
Accumulated Deferred Taxes	$ 0	$ 0	$ 0	$ 0	($ 293,855)
Average Rate Base	$ 0	$ 0	$ 0	$ 0	$ 6,296,179
Revenue Requirement:					
Book Depreciation Expense	$ 0	$ 0	$ 0	$ 0	$ 157,615
O&M expense	$ 0	$ 0	$ 0	$ 0	$ 0
Return and taxes	$ 0	$ 0	$ 0	$ 0	$ 518,176
Total Revenue Requirement	$ 0	$ 0	$ 0	$ 0	$ 675,791

Prepared by or under the supervision of: Stephanie Briggs

Division 4-6

Request:

Please provide a bill impact analysis for a typical residential customer and a small Commercial customer for the two rate recovery options proposed by the Company.

Response:

Please see the below tables for the bill impacts for a typical residential customer using 500 kWh a month and a small commercial customer using 1,000 kWh a month. Please note that the FY 2025 bill impacts represent the increases related to the DG project revenue requirement compared to rates in effect January 1, 2024 and using the FY 2025 kWh forecasts. The bill impacts will vary using actual rates in effect when the DG project rates are effective as well as the updated forecasted kWh at that time. For FY 2026 through FY 2029 bill impacts in the tables below, the impacts only reflect the change in the DG project revenue requirement for those years as compared to the prior fiscal year. The other factors on the bill as well as the kWh forecast have not been updated for this analysis but would be updated at the time of a rate change related to DG projects.

Typical Residential Customer using 500 kWh/month	**FY2025 (Increase per month compared to 1/1/24 rates)**		**FY2026 (Increase per month from FY2025 rates)**		**FY2027 (Increase per month from FY2026 rates)**		**FY2028 (Increase per month from FY2027 rates**		**FY2028 (Increase per month from FY2027 rates)**	
	$	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Scenario (a)	$0.06	.04%	$0.06	.04%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Scenario (b)	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.06	.04%

Typical C&I Customer using 1,000 kWh/month	**FY2025 (Increase per month compared to 1/1/24 rates)**		**FY2026 (Increase per month from FY2025 rates)**		**FY2027 (Increase per month from FY2026 rates)**		**FY2028 (Increase per month from FY2027 rates**		**FY2028 (Increase per month from FY2027 rates)**	
	$	**%**	**$**	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Scenario (a)	$0.10	.03%	$0.10	.03%	$0.00	0.0%	($0.01)	(0.0)%	$0.00	0.0%
Scenario (b)	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.10	.03%

Prepared by or under the supervision of: Stephanie Briggs

Division 4-7

Request:

In determining the revenue requirements for its two rate recovery options, how does the Company account for any tax credits that developers receive as subsidization for the cost of deploying their projects?

Response:

In determining the revenue requirements for the two rate recovery options, the Company did not account for any tax credits that developers may receive as a subsidization for the cost of deploying their projects. If the developers' costs were eligible for any tax credits, it would be the responsibility of the developer to accurately report to the IRS the costs incurred to deploy the project. If the developer is later reimbursed by the Company for some or all of the costs, it would still be the responsibility of the developer to amend and accurately report to the IRS the costs they incurred to deploy the project.

Prepared by or under the supervision of: Stephanie Briggs

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

February 9, 2024
Date

Docket No. 23-37-EL Rhode Island Energy – Petition for Acceleration Due to DG Project – Tiverton Projects
Service List updated 2/7/2024

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