DAYMARK® ENERGY ADVISORS

MEMORANDUM

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Aliea Afnan Munger and Bohdan Melenchuk, DAYMARK ENERGY ADVISORS
On Behalf of the Division of Public Utilities and Carriers

Date: March 14, 2025

Subject: Rhode Island Energy 2025 Annual Retail Rate Filing – Docket No. 25-04-EL

INTRODUCTION

On February 14, 2025, Rhode Island Energy ("RI Energy" or "the Company") filed its 2025 Retail Rate Filing. This filing consists of rate adjustments primarily arising out of the reconciliation of the Company's Last Resort Service ("LRS"), LRS administrative costs, the non-bypassable transition charge, transmission service charge, transmission-related uncollectible expense, net-metering credits, and long-term renewable energy contracts during the reconciliation period. The reconciliation period for the various costs in this filing is January 1, 2024, through December 31, 2024. The proposed rate adjustments are effective for usage on and after April 1, 2025. The net effect of all proposed rate changes for a residential LRS customer using 500/kWh per month is an increase of $0.07 or 0.04%. Based on the Rhode Island Public Utilities Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2025 Annual Retail Rate Filing. This filing was designated as Docket No. 25-04-EL.

The Rhode Island Division of Public Utilities and Carriers ("Division") has retained Daymark Energy Advisors to assist in its review of this filing to ensure the various reconciliations are accurately calculated and are in accordance with the relevant tariffs.

This memorandum presents the full results of our review.

LAST RESORT SERVICE ADJUSTMENT FACTORS

The Company is proposing to adjust two LRS-related rate charges: (1) LRS adjustment factor; and (2) LRS administrative cost adjustment factor. The adjustment factor is used to collect (or refund) net under- or over-recovery of LRS expenses. The LRS administrative adjustment factor is the sum of an administrative cost factor – designed to collect projected administrative expenses related to the provision of LRS – and an LRS administrative cost reconciliation adjustment factor – accounting for any under- or over-recovery of prior period LRS administrative costs. The Company is proposing LRS Adjustment Factors applicable to only LRS customers during the April 2025 through March 2026 period.[1]

For the first charge, the LRS reconciliation adjustment, the filing at Schedule NECO-2, p. 1, shows a net over-recovery (with interest) of approximately $11.7 million in calendar year ("CY") 2024, compared to the over-recovery (with interest) of approximately $26.2 million in CY 2023. This CY 2024 total is a sum of the separately calculated totals for each of the three LRS customer groups: Residential, Commercial, and Industrial. The Residential and Commercial groups had over-recoveries (with interest) of approximately $8.9 and $3.5 million, respectively, and the Industrial group had an under-recovery (with interest) of approximately $0.65 million.[2]

Additionally, as a result of Order 23366 in Docket 4809, the Company began removing capacity costs from the full requirement services contracts used to procure power for the three customer groups and included estimates of capacity payments in Standard Offer Service ("SOS")[3] rates beginning in April 2019.[4] These calculations show that there was an over-recovery of capacity costs for residential customers of $2.2 million, and under-recoveries for commercial and industrial customers of $0.57 million and $0.13 million, respectively.[5] According to the Joint Pre-filed Direct Testimony of Oliveira, these costs are inherently included in the over/under-recovery balance of the LRS base reconciliation shown on page 7 of Schedule NECO-2 and contribute to the total over- or under-recovery for each class, excluding spot market purchases.[6]

The LRS reconciliation adjustment for CY 2024 includes the additional following adjustments: $964,907 reflecting the remaining balance of CY 2022 net under-recovery LRS expenses.[7] The net unbilled billing adjustment revenue for CY 2024 is $0 for Residential, Commercial and Industrial LRS customers. There was no refund issued to customers and it was found that the Unbilled LRS billing adjustment[8] was unnecessary.

On a per kWh basis, the charge with the largest magnitude LRS adjustment is a 0.006 cents/kWh credit for the Commercial class.[9] This is compared to a CY 2023 credit of 0.024 cents/kWh. The LRS adjustment for the Residential class is a charge of 0.0035 cents/kWh compared to a credit of 0.777 cents/kWh last year. The Industrial class will be credited 0.0055 cents/kWh compared to a credit of 0.074 cents/kWh last year.[10] When asked in Div 1-1 about the swings in net over- and under-recovery to the different LRS groups, the Company confirmed the four factors that can contribute to these swings: (1) Fixed prices for the Residential and Commercial classes are developed using monthly kWh estimates that may differ from the actual monthly distribution across the rate period; (2) line losses used to develop LRS retail rates are estimated and may vary from actual line losses; (3) estimated spot market prices are used to develop the retail LRS

[1] Testimony of Oliveira, p.9, lines 15-18.
[2] Schedule NECO-2, p. 2-4.
[3] Standard Offer Service expired December 31, 2020, and Last Resort Service became effective January 1, 2021.
[4] Testimony of Oliveira, p. 14 lines 14-15.
[5] Schedule NECO-2, p. 7.
[6] Company response to Div. 1-3.
[7] Schedule NECO-2, p. 1.
[8] Unbilled LRS billing adjustment is intended to shift costs to all customers.
[9] Schedule NECO-3, p. 1.
[10] Schedule NECO-3, p. 1.

rates and actual spot market prices may differ; and (4) customers are billed on a billing cycle basis while the Company is billed for LRS expenses on a calendar month basis.[1] Our review indicates the LRS reconciliation adjustment factors are consistent with the underlying data and the requirements set forth in tariff R.I.P.U.C. No. 2237.

The Administrative Cost Factor includes an allowance for LRS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2025 filing shows total administrative expense of approximately $7.65 million[2] compared to approximately $7.77 million in the 2024 filing. The cash working capital requirement is approximately $40.6 million,[3] compared to $41.7 million in the 2024 filing.

As with the LRS Adjustment Factor, separate LRS Administrative Cost Factors are calculated for the three customer groups. The estimated LRS Administrative Cost Factor is calculated by dividing the customer group's portion of the Administrative Cost Factor by the estimated kWh sales for that customer group. The LRS Administrative Cost Reconciliation Adjustment Factor for each class is then added to the estimated LRS Administrative Cost Factor to yield the final LRS Administrative Cost Factor.

LRS Administrative Cost Reconciliation Adjustment Factor is based upon the over- or under-collection of administrative costs for the prior year. For the 2025 filing, the Company reports a net under-collection of 2024 administrative costs of approximately $0.97 million (with interest).[4] The Residential and Commercial customer groups showed under-collections of $0.72million and $0.37 million, respectively, while the Industrial customer group showed an over-collection of $0.11 million.[5] This net under-collection is largely due to a combination of higher Residential and Commercial customer group expenses than revenues.

Both the estimated administrative costs and under-collection of 2024 administrative costs are divided by the forecast LRS kWh sales by customer group to arrive at three different factors. We find that RI Energy's calculation of these charges appears to be supported by the data and should be approved.

TRANSITION CHARGE

The Transition Charge itself is a function of the contract termination charges ("CTC") billed to Rhode Island Energy by New England Power Company ("NEP") and Montaup Electric Company. The CTC is calculated by aggregating the individual CTCs and dividing them by the total GWh deliveries, resulting in a weighted average base Transition Charge. The previous Transition Charge was a credit primarily because NEP and Montaup received net credits for actual nuclear decommissioning and other post shut-down costs, which were estimated to be zero starting in 2011. Connecticut Yankee, Maine Yankee, and Yankee Atomic (collectively referred to as "the Yankees") filed suit against the Department of Energy ("DOE") for its failure

[1] Company response to Division 1-1(a).
[2] Schedule NECO-4, p. 1, col. (a), row (3).
[3] Schedule NECO-6, p. 1, row (3).
[4] Schedule NECO-5, p. 1, row (17).
[5] Schedule NECO-5, p. 2-4.

to remove the Yankees' respective spent nuclear fuel stores as required by law. So far, money has been awarded in four Phases, covering different time periods.[1]

The Company is not proposing a base Transition Charge in this filing. "The PUC directed the Company to submit a Non-Bypassable Transition Charge Adjustment Provision providing that CTC credits billed to the Company be credited to the Company's Storm Fund."[2] The proposed Transition Adjustment Factor Charge is 0.001 cents/kWh, from the total recovery amount of $131,129 being divided by the forecasted kWh deliveries for the April 1, 2025, through March 31, 2026, period.[3]

Overall, we find that the Transition Adjustment Charge to be consistent with the underlying data presented and the Company's tariff. We recommend that the charge be approved.

TRANSMISSION SERVICE CHARGE

The Company has estimated its 2025 costs for transmission service to be $298.8 million.[4] Table 1 below provides a summary of this estimate and compares it to previous estimates used to establish transmission service charges in the two previous years. The forecasted transmission costs from 2023 to 2024 increased by $25.2 million (12%), while the 2025 projected value increased the transmission costs by $63.4 million (27%) relative to the 2024 transmission cost forecast.

Ln #	Item		Feb-23	Feb-24	Incr/(Decr)	Feb-25	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 28,302,440	$ 30,115,497	$ 1,813,057	$ 52,407,311	$ 22,291,814	74%
2	Other RIE Charges		$ 1,303,242	$ 1,778,927	$ 475,685	$ 881,800	$ (897,127)	-50%
3	BITS Surcharge		$ 9,832,684	$ 12,578,217	$ 2,745,533	$ 12,754,668	$ 176,451	1%
4		*Subtotal*	$ 39,438,366	$ 44,472,641	$ 5,034,275	$ 66,043,778	$ 21,571,138	49%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 162,535,111	$ 180,970,614	$ 18,435,503	$ 220,954,546	$ 39,983,932	22%
6	Scheduling & Dispatch		$ 1,999,716	$ 2,268,191	$ 268,475	$ 2,588,775	$ 320,584	14%
7	Black Start		$ 2,126,081	$ 2,482,951	$ 356,870	$ 2,850,060	$ 367,108	15%
8	Reactive Power		$ 1,127,765	$ 1,375,084	$ 247,319	$ 1,370,760	$ (4,324)	0%
9	IROL-CIP		$ -	$ -	$ -	$ 155,659	$ 155,659	
10		*Subtotal*	$ 167,788,673	$ 187,096,840	$ 19,308,167	$ 227,919,799	$ 40,822,960	22%
	ISO-NE Administrative Charges							
11	Schedule 1 - Scheduling & Dispatch		$ 2,676,068	$ 3,568,640	$ 892,572	$ 4,282,092	$ 713,452	20%
12	Schedule 3 - Reliability Admin. Service		$ 105,073	$ 82,607	$ (22,466)	$ 430,610	$ 348,003	421%
13	Schedule 5 - NESCOE		$ 96,059	$ 112,544	$ 16,485	$ 101,812	$ (10,732)	-10%
14		*Subtotal*	$ 2,877,200	$ 3,763,791	$ 886,591	$ 4,814,514	$ 1,050,723	28%
15		**Total**	**$ 210,104,239**	**$ 235,333,271**	**$ 25,229,032**	**$ 298,778,091**	**$ 63,444,821**	**27%**

Table 1. Summary of 2023-2025 Transmission Costs

[1] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.
[2] Testimony of Shields, p. 5, lines 14-17.
[3] Testimony of Shields, p. 7, lines 9-10.
[4] Testimony of Blazunas, p.5, line 18-19.

As seen in the Incr/(Decr) column in Table 1, of the approximate $63.4 million increase, the primary cost drivers are an increase of about $22.3 million for the forecasted Non-Pooled Transmission Facility ("Non-PTF") demand charges and an increase of about $40 million for the forecasted Pooled Transmission Facility ("PTF") demand charges. While the previously mentioned categories are cost drivers for the overall increase in charges, all but three categories also increased, leaving Other NEP Charges, Reactive Power charges, and NESCOE charges as the only categories with a decrease as compared to 2024.

The increase in the PTF demand charge comes from ISO-NE. These are for PTFs that receive regional funding support. PTF charges fluctuate yearly based on the projects that are approved by ISO-NE, or asset condition projects that are included in FERC (Federal Energy Regulatory Commission) formula rates. The increase in PTF demand charges is primarily driven by an average increase in load of 22,785 kW year-over-year and the forecasted Regional Network Service ("RNS") rates.[1] Load changes resulted in a $3.3 million increase with RNS rates, resulting in the remaining $36.7 million, totaling a $40 million increase in the PTF Demand Charge.

The increase in estimated non-PTF demand charges results in part from an increase in non-PTF related load by 37,729 kW monthly. While load contributed to part of the increase, the main driver is the increase in the Local Network Service ("LNS") rate used to calculate non-PTF charges.[2] The non-PTF demand charge was calculated with LNS rates. Total non-PTF demand charge costs increased $21.4 million during the April 2025 – March 2026 period.[3]

As shown in the tables above, the BITS Surcharge is another NEP charge to RI Energy, put into effect on November 1, 2016. This surcharge was approved by the FERC, under Schedule-21 of the ISO/RTO Tariff, to recover the Company's share of the costs for the Block Island Cable and associated facilities linked with the Town of New Shoreham Project. This project is a public policy undertaking that allowed for the construction of a small-scale offshore wind power demonstration project off the coast of Block Island. Annual costs of these facilities are recovered through a reconciling rate adjustment from RI Energy's customers and/or from the Block Island Utility District d/b/a Block Island Power Company ("BIPCo"). As of January 1, 2023, the BITS Surcharge allocation to RI Energy is calculated based on an amended formula that equals the Facilities charge for the BITS facilities multiplied by the Narragansett Electric Company's Load Share Percentage. The Load Share Percentage is calculated as one (1) less BIPCo's Load Share Percentage based on the prior year's load data.[4] The Facilities Charge is the sum of several components, which consists of BITS Gross Plant Investment multiplied by the Annual Distribution Facilities Carrying Charge (excluding Primary Related Municipal Tax Expense, Primary Operation and Maintenance Expense, and Primary Related Administrative and General Expense), actual BITS Municipal Tax Expense, Actual BITS Operation and Maintenance Expense, and 2.5% of the Total Primary Related Administrative and General Expense.[5] and is set to be updated annually around June each year.[6] Beginning January 1, 2023, The

[1] Testimony of Alexei Spinu, p. 27, lines 14-18.
[2] Testimony of Alexei Spinu, p. 27, lines 6-9.
[3] Testimony of Alexei Spinu, p. 27, lines 9-12.
[4] Testimony of Alexei Spinu, p. 17, lines 19-20 – p. 18, lines 1-2.
[5] Testimony of Alexei Spinu, p. 17, lines 11-18.
[6] Testimony of Alexei Spinu, p. 17, line 20 – p. 18, line 1.

Narragansett Electric Company and BIPCo have been charged the BITS surcharge as calculated by RI Energy that are passed through to retail customers under the Transmission Service Cost Adjustment.[1] In this forecast, the estimated BITS Surcharge to Narragansett for April 2024 through March 2025 is $0.18 million more than last year's filing.[2]

Schedule NECO-10 provides the estimated annual surcharge calculation, which is passed through to customers under the Transmission Service Cost Adjustment.

The Company proposes to recover the estimated 2024 costs via demand and energy charges as appropriate for each rate class. Schedule NECO-10 provides the details of this allocation. In previous years, the allocators used to assign estimated transmission costs to each rate class were a weighted average of energy use for the 12 months ending 12/31/2008, 12 months ending 12/31/2011, and 12 months ending 6/30/2017 (Test Year used in the Company's last rate case – Docket 4770), as these were years with relatively normal weather. The use of more recent years to develop the allocators was ordered by the PUC in Docket 4805 based on our recommendation. Since Docket 4805, the Company has added to the data set the 12 months ending 6/30/2017 in these last five years.[3] Following our subsequent recommendation in Docket 23-03-EL, the Company has agreed "to consider using a more recent set of years to develop the allocators…",[4] and has conducted a study to compare the allocators for forecasted transmission expenses for 2022, 2023 and 2024 with the actual transmission expenses for the same time frame and implemented a new approach to develop allocators forecasted transmission expense using the actual average coincident peak allocators from the last three years.[5]

Based upon the Company's analysis and supporting explanations provided in testimony, we find the Company's forecast of 2025 transmission cost and associated rates designed to recover that amount to be calculated correctly. We recommend that the Commission approve the charge.

TRANSMISSION SERVICE RECONCILIATION

The previous year's forecast of transmission service charges is reconciled against 2024 actual transmission service revenues and expenses. Schedules NECO-11 and NECO-12 provide the basis for this reconciliation. As of the beginning of 2025, the cumulative variance between revenues and expenses, not including interest, is an under-collection of $12,250,819 as calculated in NECO-11. The Company will charge this under-collection over the period of April 1, 2025, through March 31, 2026. Additional interest during this period is estimated by the Company to be $199,665, which brings the total to be charged to $12,450,484.[6] The beginning balance for January 2024 was $1,719,033, which was a "true-up" of the estimated December 2024 transmission expenses from Docket No. 24-07-EL with the actual December 2023

[1] Testimony of Alexei Spinu, p. 18, lines 8-10.
[2] Schedule AS-1, p.2, col. (c), row (4).
[3] Company response to Division 1-9 in Docket 23-03-EL.
[4] Testimony of Blazunas, p. 7, lines 3-6.
[5] Testimony of Blazunas, p. 8, lines 1-4.
[6] Schedule NECO-11, p. 1, lines 16-18.

expenses.[1] This year the Schedule NECO-12 determines the cents/kWh rate for each customer class that will be refunded or charged to the respective class's share of the over/under-collection.

We find the Company's 2025 transmission reconciliation over-recovery and the rates designed to refund that amount to be calculated correctly and recommend that they be approved.

TRANSMISSION-RELATED UNCOLLECTIBLE EXPENSE

The Company's Transmission Service Cost Adjustment Provision ("TSCAP") allows it to collect from customers an estimate of transmission-related uncollectible accounts receivable, currently equal to 1.30% of the estimated amount of transmission costs to be incurred during 2025. Schedule NECO-13 provides the calculation of this amount. The TSCAP also requires the Company to reconcile its forecast of the transmission-related uncollectible accounts receivable for 2024. This reconciliation occurs only for actual 2024 revenue. Schedule NECO-14 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule NECO-14 for 2024 used a weighted uncollectible factor of 1.30%. Using a representative sample analysis, we find the calculations in Schedule NECO-13 and NECO-14 to be accurate and recommend that the rates contained therein be approved.

NET METERING CHARGE

The Net Metering charge recovers the costs of renewable Net Metering credits and payments to qualifying facilities in excess of payments the Company receives from ISO-NE for the sale of this energy in the market. The Company is proposing to increase the Net Metering Charge to 1.457 cents/kWh[2] from 1.253 cents/kWh. The Net Metering charge, including adjustments, for the 2024 under-recovery was $111,374,524.[3] This is an increase from $92,218,200 in 2023.[4]

Daymark issued a data request seeking further explanation and corrections of the Net Metering data included in the filing. In general, the Company did not highlight any major issues that materialized in the filing. RI Energy's calculation of this charge appears to be supported by the data. Daymark recommends it be approved.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base Long-Term Contracting for Renewable Energy Recovery ("LTCRER") is a 0.537 cents/kWh charge.[5] RI Energy proposes to adjust this by adding the LTCRER Reconciliation Factor of 0.118 cents/kWh,[6] bringing the net LTCRER to 0.656[7] cents/kWh starting April 1, 2024. [8] The LTCRER Reconciliation Factor is

[1] Testimony of Blazunas, p. 11, lines 7-13.
[2] Schedule NECO-15, p. 1.
[3] Schedule NECO-15, p. 1.
[4] Schedule NECO-15, p. 3.
[5] Schedule NECO-17, p. 1, row (23).
[6] Schedule NECO-17, p. 1, row (22).
[7] Company response to PUC 1-2, the LTCRER charge was revised from 0.655 cents/kWh to 0.656 cents/kWh.
[8] Schedule NECO-17, p. 1, row (24).

used to collect (or refund) any under- (or over-) recovery of Long-Term Contracting expenses. For 2024, RI Energy reports an under-recovery of approximately $9.0 million (with interest).[1] The under-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds, RI Energy must calculate a transfer price. RI Energy provided the transfer price in its workpapers, and it appears to be reasonable. The under-recovery balance reflects an adjustment of $326,590 shown in March 2024.[2] This adjustment represents an over-recovered balance of the over-recovery incurred during 2023 and credited to customers during the period ending March 31, 2025. RI Energy's calculation of the LTCRER Reconciliation Factor appears to be supported by the data provided and is in accordance with R.I.P.U.C. No. 4673. We recommend the proposed rate be approved.

RECOMMENDATION

Following the review of RI Energy's testimony and responses to data requests, Daymark finds that RI Energy calculated all the charges appropriately based on the underlying data the Company presented and according to the Company's tariff. Daymark recommends the Commission approve the proposed reconciliation of the Company's 2025 retail rate filing.

[1] Schedule NECO-17, p. 1, row (18).
[2] Schedule NECO-17, p. 1, col. (d).