State of Rhode Island
Office of the Attorney General

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Peter F. Neronha
Attorney General

March 12, 2024

Via Electronic Mail

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

RE: Docket 24-07-EL Rhode Island Energy 2024 Annual Retail Rate Filing

Dear Ms. Massaro:

On behalf of the Division of Public Utilities and Carriers, please accept for filing the attached Memorandum from Aliea Afnan Munger and Bohdan Melenchuk of Daymark Energy Advisors, which provides the Division's position in the above-entitled docket.

Thank you for your attention to this submission.

Very truly yours,

/s/ Gregory S. Schultz
Gregory S. Schultz
Special Assistant Attorney General
On behalf of the Division of Public Utilities and Carriers

Enclosure

cc: 24-07-EL Service List
Linda George, Esq., Division Administrator
Christy Hetherington, Esq., Division Chief Legal Counsel
Paul Roberti, Esq., Division Chief Economic and Policy Analyst

DAYMARK® ENERGY ADVISORS

MEMORANDUM

To: **Rhode Island Division of Public Utilities and Carriers**

From: **Aliea Afnan Munger and Bohdan Melenchuk, DAYMARK ENERGY ADVISORS**

Date: **March 12, 2024**

Subject: **Rhode Island Energy 2024 Retail Electric Rate Filing – Docket No. 24-07-EL**

INTRODUCTION

On February 16, 2024, Rhode Island Energy ("RI Energy" or the "Company") filed its 2024 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, transition adjustment, transmission service charge, transmission service cost adjustment factors, the Net Metering Charge, and the Long-Term Contracting for Renewable Energy Recovery Factor ("LTC Recovery Factor"). The reconciliation period for the various costs in this filing is January 2023 through December 2023. The proposed rate adjustments are effective for usage on and after April 1, 2024. The net effect of all proposed rate changes for a residential LRS customer using 500/kWh per month is an increase of $2.45 or 1.46%. 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 2024 Annual Retail Rate Filing. This filing was designated as Docket 24-07-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. We find that RI Energy calculated all the charges appropriately based on the underlying data the Company presented and according to the Company's tariff.

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) a LRS adjustment factor and (2) the 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 all retail delivery service customers by April 1, 2024 in anticipation of additional approved municipal aggregations.[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 $26.2 million in calendar year ("CY") 2023, compared to the under-recovery (with interest) of approximately $18.3 million in CY 2022. This CY 2023 total is a sum of the separately calculated totals for each of the three LRS customer groups: Residential, Commercial, and Industrial. The Residential, Commercial and Industrial groups had over-recoveries (with interest) of approximately $24.1 million, $0.5 million and $1.6 million, respectively.[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 were under-recoveries of capacity costs for residential and commercial customers of $4.0 million and $0.4 million, respectively, and an over-recovery for industrial customers of $7,534.[5] According to the Joint Pre-filed Direct Testimony of Blazunas, Souza, Shields, Oliveira, Salk, 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 2023 includes the additional following adjustments: $483,677 reflecting the remaining balance of CY 2021 net under-recovery SOS expenses.[7] The net unbilled billing adjustment revenue for CY 2023 is the combination of $1,773 [8] for Residential and $16,739 [9] for Commercial LRS customers. These amounts equate to a charge or revenue deficiency of $18,512.[10] The Company is proposing to recover the remaining LRS reconciliation balance from all customers.[11]

On a per kWh basis, the charge with the largest magnitude LRS adjustment is a 0.777 cents/kWh credit for the Residential class.[12] This is compared to a CY 2022 charge of 0.388 cents/kWh. The LRS adjustment for the Commercial class is a credit of 0.024 cents/kWh compared to a charge of 0.265 cents/kWh last year. The Industrial class will be credited 0.074 cents/kWh compared to a charge of 0.057 cents/kWh last year.[13] When asked in Docket 4805 about the swings in net over- and under-recovery to the different LRS groups, the Company provided four factors that can contribute to these swings: (1) Fixed prices for the Residential

[1] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 13, lines 1-2.
[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 Blazunas, Souza, Shields, Oliveira, Salk, p. 14, line 21, lines 17-20.
[5] Schedule NECO-2, p. 7.
[6] Company response to Div. 1-1.
[7] Schedule NECO-2, p. 1.
[8] Schedule NECO-8, p. 1, col. (a).
[9] Schedule NECO-8, p. 1, col. (b).
[10] Schedule NECO-8, p. 1, col. (c).
[11] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 22, line 21 – p. 23, lines 1-3.
[12] Schedule NECO-3, p. 1.
[13] Schedule NECO-3, p. 1.

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 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 2024 filing shows total administrative expense of approximately $7.77 million[2] compared to approximately $9.77 million in the 2023 filing. The cash working capital requirement is approximately $41.7 million,[3] compared to $61.5 million in the 2023 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 2024 filing, the Company reports a net under-collection of 2023 administrative costs of approximately $1.4 million (with interest).[4] The Residential, and Commercial, customer groups showed under-collections of $801,107 and $586,690, respectively, while the Industrial customer group showed an over-collection of $16,515.[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 2023 administrative costs are divided by the forecasted LRS kWh sales by customer group to arrive at three different factors. We find that RI Energy's calculation of these charges appear to be supported by the data and should be approved.

TRANSITION CHARGE

RI Energy is requesting changes to only the transition adjustment charge. The transition adjustment charge is used to account for prior under- or over-collection of these costs. For 2024, the adjustment charge is due to an under-recovery of charges in CY 2023. The transition adjustment charge is calculated by dividing the over-recovery balance from 2023 by the forecasted kWh deliveries during the recovery period, April 2024 through March 2025. This adjustment incorporates the final balance of under-recovery incurred in CY 2021.

[1] Company response to Division 1-1(a) in Docket No. 4805.
[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.

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. 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 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 0.000 cents/kWh, the total recovery amount of $58,590 and after being divided by the forecasted kWh deliveries for the April 1, 2024 through March 31, 2025 period the Company found that this under-recovery is too small to generate a billable factor[3] and proposed to carry this under-recovery to next year's retail rate filing.[4]

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 2024 costs for transmission service to be $235.3 million.[5] 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 2022 to 2023 decreased by $28.8 million (13.7%), while the 2024 projected value increased the transmission costs by $25.2 million (12%) relative to the 2023 transmission cost forecast.

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[1] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.
[2] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 23, lines 19-21.
[3] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 25, lines 12-16.
[4] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 25, lines 16-17.
[5] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p.27, line 13.

Ln #	Item		Feb-22	Feb-23	Incr/(Decr)	Feb-24	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 43,568,259	$ 28,302,440	$ (15,265,819)	$ 30,115,497	$ 1,813,057	6%
2	Other NEP Charges		$ 415,157	$ 1,303,242	$ 888,085	$ 1,778,927	$ 475,685	37%
3	BITS Surcharge		$ 10,521,889	$ 9,832,684	$ (689,205)	$ 12,578,217	$ 2,745,533	28%
4		*Subtotal*	$ 54,505,305	$ 39,438,366	$ (15,066,939)	$ 44,472,641	$ 5,034,275	13%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 175,777,000	$ 162,535,111	$ (13,241,889)	$ 180,970,614	$ 18,435,503	11%
6	Scheduling & Dispatch		$ 2,221,149	$ 1,999,716	$ (221,433)	$ 2,268,191	$ 268,475	13%
7	Black Start		$ 2,146,679	$ 2,126,081	$ (20,598)	$ 2,482,951	$ 356,870	17%
8	Reactive Power		$ 1,262,382	$ 1,127,765	$ (134,617)	$ 1,375,084	$ 247,319	22%
9		*Subtotal*	$ 181,407,210	$ 167,788,673	$ (13,618,537)	$ 187,096,840	$ 19,308,167	12%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,824,067	$ 2,676,068	$ (147,999)	$ 3,568,640	$ 892,572	33%
11	Schedule 3 - Reliability Admin. Service		$ 79,412	$ 105,073	$ 25,661	$ 82,607	$ (22,466)	-21%
12	Schedule 5 - NESCOE		$ 104,985	$ 96,059	$ (8,926)	$ 112,544	$ 16,485	17%
13		*Subtotal*	$ 3,008,464	$ 2,877,200	$ (131,264)	$ 3,763,791	$ 886,591	31%
14		**Total**	**$ 238,920,979**	**$ 210,104,239**	**$ (28,816,740)**	**$ 235,333,271**	**$ 25,229,033**	**12%**

Table 1. Summary of 2022-2024 Transmission Costs

As seen in the Incr/(Decr) column in Table 1, of the approximate $25.2 million increase, the primary cost driver is an increase of about $18.4 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 one category also increased leaving the Reliability Admin. Service charges as the only categories with a decrease as compared to 2023.

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 increase in load by 242,980 kW and the forecasted Regional Network Service ("RNS") rates.[1] Load changes resulted in a $3 million increase with RNS rates resulting in the remaining $15.4 million, totaling an $18.4 million increase in PTF Demand Charge.

The increase in estimated Non-PTF demand charges results from an increase in non-PTF related load by 128,592 kW in total. 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 which increased $1.51 million during the January 2023 – March 2025 period.[3] Also, the Block Island Transmission System ("BITS") surcharge used 5.82% in last year's estimated distribution carrying charge, compared to this year's 7.41%, resulting in a $2.75 million increase.[4]

[1] Testimony of Alexei Spinu, p. 26, lines 12-18.
[2] Testimony of Alexei Spinu, p. 25, lines 13-20.
[3] Testimony of Alexei Spinu, p. 25, lines 16-19.
[4] Testimony of Alexei Spinu, p. 26, lines 1-3.

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.[1] The Facilities charge is the sum of several components including, BITS Gross Plant Investment multiplied by the Annual Distribution Facilities Carrying Charge, actual BITS Municipal Tax Expense, Actual BITS Operation and Maintenance Expense and 2.5% of the Total Primary Related Administrative and General Expense and is set to be updated annually around June each year.[2] Beginning January 1, 2023, The Narragansett Electric Company and BIPCo will be charged the BITS surcharge as calculated by RI Energy that are passed through to retail customers under the Transmission Service Cost Adjustment.[3] In this forecast, the estimated BITS Surcharge to Narragansett for April 2023 through March 2024, $2.75 million more than last year's filing.

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 2023 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 are a weighted average of energy use for 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 are 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. However, since Docket 4805, the Company has added to the data set the 12 months ending 6/30/2017 in these last five years.[4] Following our recommendation in Docket 23-03-EL, the Company has agreed "to consider using a more recent set of years to develop the allocators…",[5] and has conducted a study to compare the allocators for forecasted transmission expenses for 2021, 2022 and 2023 with the actual transmission expenses for the same time frame; and proposed a new approach to develop allocators forecasted transmission expense using the actual average coincident peak allocators from the last three years.[6]

[1] Testimony of Alexei Spinu, p. 16, lines 15-19.
[2] Testimony of Alexei Spinu, p. 16, lines 6-13.
[3] Testimony of Alexei Spinu, p. 17, lines 1-4.
[4] Company response to Division 1-9 in Docket 23-03-EL.
[5] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 29, lines 8-9.
[6] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 31, lines 3-5.

Based upon the Company's analysis and supporting explanations provided in testimony, we find the Company's forecast of 2024 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 2023 actual transmission service revenues and expenses. Schedules NECO-11 and NECO-12 provide the basis for this reconciliation. As of the beginning of 2024, the cumulative variance between revenues and expenses, not including interest, is an under-collection of $9,263,149 as calculated in NECO-11. The Company will charge this under-collection over the period of April 1, 2024 through March 31, 2025. Additional interest during this period is estimated by the Company to be $119,347, which brings the total to be charged to $9,382,496.[1] The beginning balance for January 2023 was $422,646 which was a "true-up" of the estimated December 2023 transmission expenses from Docket No. 23-03-EL with the actual December 2022 expenses.[2] 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. Using a representative sample analysis, we find the calculations in Schedule NECO-12 to be accurate.

We find the Company's 2024 transmission reconciliation over-recovery and the rates designed to refund that amount to be calculated correctly, supported by data, 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 2024. 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 2023. This reconciliation occurs only for actual 2023 revenue. Schedule NECO-14 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule NECO-14 for 2023 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 a Net Metering charge change to 1.253 cents/kWh[3] from 0.628 cents/kWh. The

[1] Schedule NECO-11, p. 1, lines 16-18.

[2] Testimony of Blazunas, Souza, Shields, Oliveira, Salk, p. 33, lines 2-8.

[3] Schedule NECO-15, p. 1.

net metering charge including adjustments for 2023 was $92,218,200.[1] This is an increase from $46,070,988 from 2022.[2]

The Division issued a series of data requests seeking further explanation of the Net Metering Generation Credits included in the filing. In general, the Company did not highlight any major issues (errors, data corrections, etc.) that materialized in the filing. The Company also explained that it is working with National Grid to retrieve the workpapers requested. Subject to any issues identified in the workpapers provided by the Company (currently pending), 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 0.425 cents/kWh credit. RI Energy proposes to adjust this by adding the LTCRER Reconciliation Factor of 0.555 cents/kWh,[3] bringing the net LTCRER to 0.98 cents/kWh starting April 1, 2024.[4] The LTCRER Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of Long-Term Contracting expenses. For 2023, RI Energy reports an under-recovery of approximately $40.3 million (with interest).[5] 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 $301,232 shown in April 2023.[6] This adjustment represents an over-recovered balance of the over-recovery incurred during 2022 and credited to customers during the period ending March 31, 2024. 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.

ADDITIONAL CONSIDERATIONS

In addition to the analysis completed and summarized above, Daymark issued a series of data requests to better understand the Company's calculations and methodology behind Qualifying Facilities (QF), the inclusion of Mystic Cost of Service ("CoS") charges, and if any changes were made in the filing per the recent Rhode Island Commission Motions approved in January 2024 at Docket No. 23-05-EL.

RI Energy's explanations and additional detail provided in Division 2-3 support the values included in the filing; Schedule NECO-15 and accompanying testimony. In 2023, QF costs rose due to three major drivers: (1) lower MWhs (from 4,713 MWh in 2022 to 4,198 MWh in 2023), (2) increased QF payouts due to a higher LRS rate, and (3) lower ISO bill credits (from $427,283 in 2022 down to $161,290 in 2023).

[1] Schedule NECO-15, p. 1.
[2] Schedule NECO-15, p. 3.
[3] Schedule NECO-17, p. 1, row (22).
[4] Schedule NECO-17, p. 1, row (24).
[5] Schedule NECO-17, p. 1, row (18).
[6] Schedule NECO-17, p. 1, col. (d).

Collectively, lower credits and increasing payout costs drove higher overall QF costs, to be recovered from customers. No further analysis appears warranted at this time.

Daymark sought to better understand if Mystic CoS charges were recovered in the LRS rates, and if so, where those charges were recovered and their associated costs. RI Energy explained that Mystic CoS charges were in fact included – embedded in LRS Expenses provided in Schedule NECO-2 Pages 1 through 4, column (c). Further, these charges are included in the capacity charges found in NECO-2 Page 6 column (b) for Residential, Commercial, and Industrial customers. Response to Division 2-4 provides monthly details on the charges embedded into the rates – with total costs for 2023 amounting to $13,887,483 across all customer classes. No additional analysis appears warranted at this time.

Finally, concerning the Commission Motions under Docket No. 23-05-EL, the Company confirmed that no changes were made to the current filing. This correctly aligns with Daymark's understanding of the Motions and their implementation. No further action appears warranted at this time.