DAYMARK ENERGY ADVISORS

MEMORANDUM

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Carrie Gilbert and Aliea Afnan, DAYMARK ENERGY ADVISORS

Date: March 18, 2021

Subject: National Grid's 2021 Retail Electric Rate Filing – Docket No. 5127

INTRODUCTION

On February 12, 2021, National Grid ("NGrid" or "the Company") filed its 2021 Retail Rate Filing. This filing consists of rate adjustments primarily arising out of the reconciliation of the Company's Standard Offer Service[1] ("SOS") and Last Resort Service ("LRS"), SOS administrative costs, the non-bypassable transition charge, transmission service charge, the transmission-related uncollectible expense charge, 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 2020 through December 2020. The proposed rate adjustments are effective for usage on and after April 1, 2021. The net effect of all proposed rate changes for a residential LRS customer using 500/kWh per month is an increase of $2.53 or 2.1%. Based on the Public Utility Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2021 Annual Retail Rates Filing. This filing was designated as Docket No. 5127.

The Rhode Island Division of Public Utilities and Carriers (the "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. In summary, we find that NGrid calculated all the charges appropriately based on the underlying data the Company presented and the Company's tariff.

This memorandum presents the full results of our review.

FALL ECONOMIC FORECAST UPDATE

The Company has presented an updated forecast in this filing using more recent data from Fall 2020, which considers the effects of the COVID-19 pandemic.[2] The economic forecast used to prepare the econometric energy deliveries forecast was developed by Moody's Analytics ("Moody's") using their December 2020 baseline forecast.[3] The assumptions with this forecast include slow economic growth in Q1 of 2021 and

[1] Standard Offer Service expired on December 31, 2020 and Last Resort Service became effective January 1, 2021.
[2] Testimony of Electric Load Forecasting Panel, p. 6, lines 7-11.
[3] Testimony of Electric Load Forecasting Panel, p. 10, line 10.

stronger economic growth in Q2 and Q3 of 2021.[1] The end of 2021 into Q1 of 2022 assumes herd immunity will be achieved for Rhode Island enabling it to fully reopen its economy.[2]

LAST RESORT SERVICE ADJUSTMENT FACTORS

The Company is proposing to adjust two SOS/LRS-related rate charges: (1) an adjustment factor to collect (or refund) net under (or over) recovery of SOS/LRS expense and (2) the SOS/LRS administrative cost adjustment factor, which is the sum of an administrative cost factor designed to collect various projected administrative expenses related to the provision of SOS/LRS and an SOS/LRS administrative cost reconciliation adjustment factor, which accounts for any under- or over-recovery of prior period SOS/LRS administrative costs.

For the first charge, the SOS/LRS reconciliation adjustment, the filing at Schedule NG-2, p. 1, shows a net over-recovery (with interest) of approximately $9.6 million in calendar year ("CY") 2020, compared to the over-recovery (with interest) of approximately $5 million in CY 2019. This CY 2020 total is a sum of the separately calculated totals for each of the three SOS/LRS customer groups: Residential, Commercial, and Industrial. These totals are then adjusted for additional interest during the recovery period and divided by forecasted customer group SOS/LRS kWh sales for April 2020 through March 2021 to calculate three different adjustment factors, one for each procurement group. The Residential and Industrial groups had over-recoveries (with interest) of approximately $13.8 million and $1.1 million, respectively. The Commercial group had an under-recovery (with interest) of $5.4 million.[3]

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 SOS rates beginning in April 2019.[4] These calculations show that there were over-recoveries of capacity costs for residential and industrial customers of $6.0 million and $.1 million and an under-recovery for commercial customers of $3 million.[5] According to the Testimony of Mr. Crary and Mr. Roughan, these costs are inherently included in the over/under-recovery balance of the SOS/LRS base reconciliation shown on pages 2-4 of Schedule NG-2 and contribute to the total over or under recovery for each class.[6]

The SOS reconciliation adjustment for CY 2020 includes the additional following adjustments: $177,268 reflecting the remaining balance of CY 2018 net under-recovery SOS expenses; and reduced the SOS reconciliation by $198,406 for unbilled SOS Billing Adjustments for CY 2020. The net unbilled billing adjustment revenue for CY 2020 is the combination of a negative $178,045[7] for Residential and a negative $20,361[8] for Commercial SOS customers. These amounts equate to a credit or revenue surplus of

[1] Testimony of Electric Load Forecasting Panel, p. 10, lines 19-21.
[2] Testimony of Electric Load Forecasting Panel, p. 11, lines 1-5.
[3] Schedule NG-2, p. 2-4.
[4] Testimony of Adam S. Crary and Timothy R. Roughan, p. 8, line 21 and p. 9, lines 1-3 .
[5] Schedule NG-2, p. 7.
[6] Testimony of Adam S. Crary and Timothy R. Roughan, p. 9 of 46, lines 11-15.
[7] Schedule NG-2, p. 2.
[8] Schedule NG-2, p. 3.

$198,406[1] as the Company paid less for the SOS supply than it billed to customers that left SOS and took electric supply from a third party.[2] NGrid is proposing this amount as an adjustment to the Revenue Decoupling Mechanism ("RDM")[3] reconciliation, which will be filed by May 15, 2021.[4] Through the RDM Adjustment Factor, all customers will be assessed a portion of the net SOS Billing Adjustment credit.

On a per kWh basis, the charge with the largest magnitude SOS/LRS adjustment is a 0.598 cents/kWh credit for the Industrial class.[5] This is compared to a CY 2020 charge of 0.381 cents/kWh. In response to Data Request PUC 1-1, the Company explained that for the Industrial group the supplier resettlement amounts through CY 2020 totaled $0.3 million and actuals costs were $0.5 million lower than estimated, resulting in a $0.8 million reduction in the Industrial group SOS expense.

The SOS/LRS adjustment for the Residential class is a credit of 0.512 cents/kWh compared to a credit of 0.294 cents/kWh last year. The Commercial class will be charged 0.568 cents/kWh compared to a charge of 0.094 cents/kWh last year.[6] When asked in Docket 4805 about the swings in net over- and under-recovery to the different SOS/LRS groups, the Company provided 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 SOS/LRS retail rates are estimated and may vary from actual line losses; (3) estimated spot market prices are used to develop the retail SOS/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 SOS/LRS expenses on a calendar month basis.[7] Our review indicates the SOS/LRS reconciliation adjustment factors are consistent with the underlying data and tariff R.I.P.U.C. No. 2113 and are reasonable.

The Administrative Cost Factor includes an allowance for SOS/LRS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2021 filing shows total administrative expense of approximately $7.64 million[8] compared to approximately $7.58 million in the 2020 filing. Uncollectible expense is lower than last year despite the projected increases in the Residential and Commercial classes demand due to lower projected LRS rates for the Commercial and Industrial classes.[9] The cash working capital requirement is $43.9 million[10], compared to $40.3 million in the 2020 filing. This increase was mostly due to an increase in the customer payment lag from an average of 64 days in 2019 to 72 days[11] in 2020 which has been attributed to the COVID-19 pandemic and delaying customers' payments.[12]

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[1] Schedule NG-2, page 1.
[2] Testimony of Adam S. Crary and Timothy R. Roughan, p. 17, lines 6-11.
[3] The RDM Adjustment Factor is a uniform per kWh factor applicable to all retail delivery service customers.
[4] Testimony of Adam S. Crary and Timothy R. Roughan, p. 18, lines 11-13.
[5] Schedule NG-3, p. 1.
[6] Schedule NG-3, p. 1.
[7] Company response to Division 1-1(a) in Docket No. 4805.
[8] Schedule NG-4, p. 1.
[9] Schedule NG-4, p. 2.
[10] Schedule NG-6, p. 1.
[11] Schedule NG-6, p. 7.
[12] Data Request PUC 1-4

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 groups 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 2021 filing, the Company reports a net under-collection of 2020 administrative costs of approximately $1.3 million (with interest).[1] The Residential, Commercial, and Industrial customer groups showed under-collections of $914,775, $318,545, and $51,821 respectively.[2] This net under-collection is largely due to a combination of higher expenses than revenues for all three customer groups.

Both the estimated administrative costs and under-collection of 2020 administrative costs are divided by the forecasted LRS kWh sales by customer group to arrive at three different factors. We find NGrid's calculation of these charges appears to be supported by the data and should be approved.

TRANSITION CHARGE

NGrid is requesting changes to both the base transition charge and transition adjustment charge. The Transition adjustment charge is used to account for prior under- or over-collection of these costs. For 2021, the adjustment charge is due to an under-recovery of charges in CY 2020. The transition adjustment charge is calculated by dividing the over-recovery balance from 2020 by the forecasted kWh deliveries during the recovery period, April 2021 through March 2022. This adjustment incorporates the final balance of over-recovery incurred in CY 2018.

The transition charge itself is a function of the contract termination charges ("CTC") billed to NGrid by New England Power Company ("NEP") and Montaup. The CTC charge is calculated by aggregating the individual CTC charges 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 three Phases, covering different time periods.[3] NEP and Montaup received proceeds for Phase I and Phase II of the litigation that were credited to customers between 2013 and 2015. No proceeds were returned by NEP and Montaup from October 1, 2015 through September 30, 2016.

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[1] Schedule NG-5, p. 1.

[2] Schedule NG-5, p. 2-4.

[3] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.

According to the 2017 CTC Reconciliation Reports[1] filed by NGrid, in December of 2016 NEP received $5.9 million in proceeds and Montaup received $1.7 million in proceeds for Phase III litigation, which they planned to return to customers in the following year's CTC reconciliation. In the 2018 CTC Reconciliation Reports[2] filed by NGrid, Phase III litigation proceeds were received in December of 2016 by Montaup and NEP in the amounts of $3.2 million and $14.8 million, respectively, and were credited to customers through the 2017 CTC reconciliation filed in January 2018.[3] NGrid did not receive excess proceeds from NEP[4] or Montaup[5] to return to customers from October 1, 2017 through September 30, 2018, but is returning $6.3 million for October through December 2018 for NEP and about $3.3 million in December 2018 for Montaup.[6,7] Reconciliation of estimated to actual deliveries were overestimated. However, the variance in deliveries was offset by the negative transition charges in 2019 and 2020 producing excess revenue aggregating approximately $1.1 million for NEP and approximately $0.55 million for Montaup.[8]

NGrid explained that the Phase III litigation proceeds described in the 2018 CTC Reconciliation Reports replaced the amounts originally provided in the 2017 CTC Reconciliation Reports.[9] The discrepancy between the 2017 and 2018 Phase III litigation proceeds for Montaup and NEP was due to changes in how Connecticut Yankee and Maine Yankee handled the proceeds. Connecticut Yankee received $32.6 million of litigation proceeds instead of $34.6 million and the company only returned $18.4 million to wholesale customers instead of the entire amount, as originally intended. The Company deposited $0.6 million of proceeds in its irrevocable external trust to fund Post Retirement Benefits Other Than Pension (PBOP), used $0.4 million of proceeds to pay the associated taxes, and deposited the remaining proceeds into the Decommissioning Trust Fund to fund long-term Independent Spent Fuel Storage Installation (ISFSI) operations and decommissioning costs.[10] Maine Yankee was awarded $24.6 million in damages, of which $3.6 million were returned to the Company's wholesale customers in December 2016, and remaining proceeds were deposited into the Decommissioning Trust Fund.[11] Yankee Atomic was awarded $19.6 million, all of which was deposited in the Decommissioning Trust Fund.[12]

Phase IV proceeds have been initially awarded in the amounts of $40.7 million to Connecticut Yankee, $28.1 million to Yankee Atomic, and $34.4 million to Maine Yankee, followed by an additional $500,000 in

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[1] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2017.
[2] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2018.
[3] Company response to Division 1-6(b), p. 3, in Docket 4930.
[4] Narragansett has a 22.4% share of the NEP proceeds.
[5] Blackstone and Newport have shares of 29.13% and 11.85%, respectively.
[6] Company response to Division 1-6(b), Attachment DIV 1-6-1, p. 10 and 14, in Docket 4930.
[7] Company response to Division 1-6(b), Attachment DIV 1-6-2, p. 7, 10, and 11, in Docket 4930.
[8] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2021.
[9] Company response to Division 1-4 in Docket 4805.
[10] Company response to Division 1-6(b), p. 2, in Docket 4930.
[11] Company response to Division 1-6(b), p. 2, in Docket 4930.
[12] Company response to Division 1-6(b), p. 2, in Docket 4930.

June 2019, for Phase IV, covering the period of 2013 to 2016. The Yankees plan to file Phase V, covering 2017 to 2020, in late spring 2021.[1]

The base transition charge credit factor for the upcoming year is 0.113 cents/kWh. When combined with the transition charge adjustment factor charge of 0.004 cents/kWh, the proposed total transition charge credit factor is 0.109 cents/kWh.[2] The change in the transition charge compared to last year's filing is primarily due to the changes in credits returned to customers during CY 2020.

Overall, we find the base transition charge credit to be consistent with the NEP charges reported in the NEP and Montaup CTC Reconciliation Reports. We also find that the adjustment factor charge to be consistent with the underlying data presented and the Company's tariff. We recommend that the charge and credit be approved.

TRANSMISSION SERVICE CHARGE

The Company has estimated its 2021 costs for transmission service to be $222.1 million, as described by the testimony of Adam S. Crary and Timothy R. Roughan. 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 2019 to 2020 increased by $2.6 million (1%), while the 2021 projected value increases the transmission costs by $22.7 million (11%) relative to the 2020 transmission cost forecast.

Ln #	Item		Feb-19	Feb-20	Incr/(Decr)	Feb-21	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 25,946,640	$ 35,745,041	$ 9,798,401	$ 39,136,736	$ 3,391,695	9%
2	Other NEP Charges		$ 360,615	$ 446,593	$ 85,978	$ 475,734	$ 29,141	7%
3	BITS Surcharge		$ 20,272,480	$ 18,961,716	$ (1,310,764)	$ 21,454,006	$ 2,492,290	13%
4		*Subtotal*	$ 46,579,735	$ 55,153,350	$ 8,573,615	$ 61,066,476	$ 5,913,126	11%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 144,304,593	$ 138,120,231	$ (6,184,362)	$ 153,493,464	$ 15,373,233	11%
6	Scheduling & Dispatch		$ 1,971,263	$ 1,856,498	$ (114,765)	$ 1,952,294	$ 95,796	5%
7	Black Start		$ 877,984	$ 1,307,372	$ 429,388	$ 1,718,686	$ 411,314	31%
8	Reactive Power		$ 1,296,001	$ 1,184,217	$ (111,784)	$ 1,206,744	$ 22,527	2%
9		*Subtotal*	$ 148,449,841	$ 142,468,318	$ (5,981,523)	$ 158,371,188	$ 15,902,870	11%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,461,473	$ 2,443,976	$ (17,497)	$ 2,457,933	$ 13,957	1%
11	Schedule 3 - Reliability Admin. Service		$ 201,233	$ 208,627	$ 7,394	$ 102,252	$ (106,375)	-51%
12	Schedule 5 - NESCOE		$ 105,915	$ 123,314	$ 17,399	$ 84,029	$ (39,285)	-32%
13		*Subtotal*	$ 2,768,621	$ 2,775,917	$ 7,296	$ 2,644,214	$ (131,703)	-5%
14		**Total**	**$ 197,798,197**	**$ 200,397,585**	**$ 2,599,388**	**$ 222,081,878**	**$ 21,684,294**	**11%**

Table 1. Summary of 2019-2021 Transmission Costs

As seen in the Incr/(Decr) column in Table 1, of the approximate $21.7 million increase, an increase of about $15.3 million in the forecasted PTF demand charges is the primary cost driver, along with an increase

[1] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2020.
[2] Testimony of Adam S. Crary and Timothy R. Roughan p. 21, lines 10-16

of $3.4 million in Non-PTF demand charges and $2.5 million in the BITS surcharge. There is a small decrease in the ISO-NE Reliability Admin service charge.

The increase in the PTF demand charge comes from ISO-NE. These are for Pooled Transmission Facilities that receive regional funding support. PTF charges fluctuate yearly based on the projects that are approved by ISO-NE. NGrid provided a 2021-2024 forecast summary of projects by utility in Attachment 1-35-2 in their response to the Commission's first set of data requests. In summary, NGrid stated that the projected increase in PTF charges is driven by the increase in RNS (Regional Network Service) rate, which is driven by the expected $1,076 million dollars of plant additions in CY 2020[1].

The estimate of Non-PTF costs incorporates NGrid's estimates of Non-PTF plant additions. These costs are estimated on a project-by-project basis. The Company provided the project-by-project costs by state.[2] The Non-PTF projects in 2020 for Massachusetts ($21.6 million), Rhode Island ($21.8 million), New Hampshire ($19.9 million), and Vermont ($0.5 million) total $63.3 million.[3] In terms of the projected increase, NGrid stated the following: "The approximately $3.4 million projected increase in NECO's Non-PTF demand charge is driven by its share of the projected increase in New England Power Company's Local Network Service revenue requirement.[4]" We have reviewed these estimates and find them to be reasonable.

As shown in the tables above, the BITS Surcharge is another NEP charge to NGrid, 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 allows for the construction of a small-scale offshore wind demonstration project off the coast of Block Island. Annual costs of these facilities will be recovered through a reconciling rate adjustment from NGrid's customers and/or from the Block Island Power Company (BIPCo). The BITS Surcharge allocation to NGrid is calculated by multiplying the integrated facilities credit received by the Company through NEP's FERC Electric Tariff No. 1 (IFA Facilities Credit), updated around June each year, by NGrid's Load Share Percentage (one (1) less BIPCo's Load Share Percentage based on the prior year's load data). Costs are then passed through to retail customers under the Transmission Service Cost Adjustment. In this forecast, the estimated BITS Surcharge to Narragansett for the April 2021 through March 2022 is about $2.5 million higher than last year's filing. This is due to the amount of capital cost that is not already covered by the surcharge rate level set for 2020.[5]

Schedule NG-11 provides the estimated annual surcharge calculation, which is passed through to customers under the Transmission Service Cost Adjustment.

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[1] Company response to Division 1-3 (a)(i) in docket 5127
[2] Company response to Division 1-3(c)(i), Attachment DIV 1-3(c)(i)
[3] Company response to Division 1-3(c)(i), Attachment DIV 1-3(c)(i)
[4] Company response to Division 1-3 (a) (ii) in docket 5127
[5] Company response to Division, 1-3 (a)(iii) in docket 5127

The Company proposes to recover the estimated 2021 costs via demand and energy charges, as appropriate for each rate class. Schedule NG-11 provides the details of this allocation. 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 recent 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.

Based upon the above discussion, we find the Company's forecast of 2021 transmission cost and the rates designed to recover that amount to be reasonable. We recommend that the Commission approve the charge.

TRANSMISSION SERVICE RECONCILIATION

The previous year's forecast of transmission service charges is reconciled against 2020 actual transmission service revenues and expenses. Schedules NG-12 and NG-13 provide the basis for this reconciliation. As of the beginning of 2020, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $2,174,908 as calculated in NG-12. The Company will refund this over-collection over the period of April 1, 2021 through March 31, 2022. Additional interest during this period is estimated by the Company to be $10,884, which brings the total to be refunded to $2,185,792. The beginning balance for January 2020 was $1,215,253 which was a "true-up" of the estimated December 2019 transmission expenses from Docket 5005 with the actual December 2019 expenses.[1] This year the Schedule NG-13 determines the cents/kWh rate for each customer class that will be refunded or charged to the respective class' share of the over/under-collection. Using a representative sample analysis, we find the calculations in Schedule NG-13 to be accurate.

We find the Company's 2021 transmission reconciliation over-recovery and the rates designed to refund that amount to be reasonable 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 2021. Schedule NG-14 provides the calculation of this amount. The TSCAP also requires the Company to reconcile its forecast of the transmission-related uncollectible accounts receivable for 2020. This reconciliation occurs only for actual 2020 revenue. Schedule NG-15 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule NG-15 for 2020 used a weighted uncollectible factor of 1.30%. Using a representative sample analysis, we find the calculations in Schedule NG-14 and NG-15 to be accurate and recommend that the rates contained therein be approved.

[1] Testimony of Adam S. Crary and Timothy R. Roughan p. 26, lines 13-19.

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 0.436 cents/kWh[1] from 0.266 cents/kWh. The net metering charge including adjustments for 2020 was $30,557,074.[2] This is an increase from $18,822,783 from 2019[3]. NGrid's calculation of this charge appears to be supported by the data and should be approved.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base LTC Recovery Factor is a 0.646 cent/kWh charge. NGrid proposes to add to this an LTC Recovery Reconciliation Factor of 0.123 cent/kWh[4], bringing the total LTC Recovery Factor to 0.769 cent/kWh starting April 1, 2021 through June 30, 2021. The LTC Recovery Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of LTC expenses. For 2020, NGrid reports an under-recovery of approximately $8.6 million (with interest). The under-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds, NGrid must calculate a transfer price. NGrid provided the transfer price in its workpapers, and it appears to be reasonable. Note, this factor will terminate on June 30, 2021 and a new factor will take its place for contracts July 1, 2021 to December 31, 2021. The under-recovery balance reflects an adjustment of $147,359 shown in April 2020.[5] This adjustment represents the remaining unrecovered balance of the under-recovery incurred during 2019 and recovered from customers during the period ending March 31, 2020. NGrid's calculation of the Long-Term Contracting for Renewable Energy Recovery ("LTCRER") reconciliation factor appears to be supported by the data provided and is in accordance with R.I.P.U.C. No. 4673. The proposed rate should be approved.

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[1] Schedule NG-16, p. 1.
[2] Testimony of Adam S. Crary and Timothy R. Roughan p. 35, line 20 and p. 36 line 1.
[3] Revised Testimony of Robin E. Pieri, p. 35
[4] Schedule NG-18, p. 1.
[5] Schedule NG-18, p. 1.