Laura C. Bickel
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September 8, 2020

VIA E-FILING

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

Re: In Re: Commission's Review of the Benefits and Costs of Net Metering Credit Calculation Pursuant to R.I. Gen. Laws § 39-26.4-3: Docket No. 5010

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid (the Company), enclosed for filing with the Rhode Island Public Utilities Commission (the Commission) please find the Company's responses to the fifth set of data requests issued by the Commission on August 24, 2020. Consistent with the instructions issued by the Commission on March 16, 2020, this filing is being made electronically. Hard copies will be submitted as soon as possible.

If you have any questions, please contact me at: 781-907-2126. Thank you for your time and attention to this matter.

Very truly yours,

Laura C. Bickel
RI Bar # 10055

Enclosures

cc: Docket No. 5010 Service List

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Docket No. 5010 Service List as of 7/23/2020

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PUC 5-1

Request:

(referencing PUC 4-1)

- Subpart (b): the Commission asked National Grid to specify when they develop the kWh sales forecast used in setting rates for 22 specific factors/charges. National Grid did not answer the question when each forecast (for each of the 22 factors/charges) is developed. Please provide a specific time that each of the forecasts is developed.

Response:

The kWh sales forecast used as the basis for setting rates is developed annually each fall (typically in September). Attachment PUC 5-1 contains a list of the dates specific to each of the 22 factors/charges listed in the original PUC 4-1 request.

LIST OF FILINGS WITH DATE OF FILING, EFFECTIVE DATE OF RATE CHANGE AND FORECAST USED

		Docket	Filing Date	Rate Change Effective Date	Release date of Forecast Used
i.	Capacity charge (unitized to a $/kWh rate), as included in the base SOS rate	4809	10/17/2019	1/1/2020	Sep-2019
		4935	1/15/2020	4/1/2020	Sep-2019
		4935	4/15/2020	7/1/2020	Sep-2019
		4935	7/17/2020	10/1/2020	Sep-2019
ii.	SOS Administrative Cost Factor	5005	2/14/2020	4/1/2020	Sep-2019
iii.	SOS Adjustment Factor	5005	2/14/2020	4/1/2020	Sep-2019
iv.	Base Distribution charge (per-kWh charge)	4770	11/27/2017	9/1/2018	Sep-2017
v.	Operating and Maintenance Expense Charge	4995	12/20/2019	4/1/2020	Sep-2019
vi.	Operating and Maintenance Reconciliation Factor	4915	8/3/2020	10/1/2020	Sep-2019
vii.	CapEx Factor Charge (per-kWh charge)	4995	12/20/2019	4/1/2020	Sep-2019
viii.	CapEx Reconciliation Factor	4915	8/3/2020	10/1/2020	Sep-2019
ix.	RDM Adjustment Factor	5030	5/15/2020	7/1/2020	Sep-2019
x.	Pension Adjustment Factor	5054	8/3/2020	10/1/2020	Sep-2019
xi.	Storm Fund Replenishment Factor	4686	12/29/2016	7/1/2017	Sep-2016
xii.	Arrearage Management Adjustment Factor	5031	5/15/2020	7/1/2020	Sep-2019
xiii.	Low-Income Discount Recovery Factor	5031	5/15/2020	7/1/2020	Sep-2019
xiv.	Base Transmission Charge (per-kWh charge)	5005	2/14/2020	4/1/2020	Sep-2019
xv.	Transmission Adjustment Factor	5005	2/14/2020	4/1/2020	Sep-2019
xvi.	Transmission Uncollectible Factor	5005	2/14/2020	4/1/2020	Sep-2019
xvii.	Base Transition Charge	5005	2/14/2020	4/1/2020	*
xviii.	Transition Charge Adjustment	5005	2/14/2020	4/1/2020	Sep-2019
xix.	Net Metering Charge	5005	2/14/2020	4/1/2020	Sep-2019
xx.	LTC Recovery Factor	4992	11/15/2019	1/1/2020	Sep-2019
		4992	5/15/2020	7/1/2020	Sep-2019
xxi.	LTC Recovery Reconciliation Factor	5005	2/14/2020	4/1/2020	Sep-2019
xxii.	Energy Efficiency Program Charge	4979	10/15/2019	1/1/2020	Sep-2019

* Uses a forecast developed years ago and is sourced from the wholesale CTC reports that are submitted to the Commission and Division.

PUC 5-2

Request:

(referencing PUC 4-3)

- Subpart (a): the Commission asked National Grid how they construct class average load shapes for customers without interval data, and using what specific data. National Grid acknowledged that they use a "stratified sample of each customer class," but did not answer how they determine that sample, how they construct the class average load shapes, nor what actual data they use in constructing them. Please answer the question in full.

Response:

For the sample classes (excluding Rate G-32), the Company constructed its load shapes using the RLW Analytics SAS-based computer model. This statistically-based computer model is considered industry standard for the electric utility industry.

The following is a summary of the methodology:

1) For each rate class, the Company organized the annual usage for each customer.
2) It then used the RLW model to:
   a. organize each rate class' customers into 3-5 stratum,
   b. determine the ranges for each stratum based on annual usage, and
   c. estimate the sample size.
3) The Company uses "random sampling" to select sample sites for each stratum within each rate class. "Random sampling" assigns an equal probability for each premise in a stratum to be selected as a sample site.
4) The Company completes an annual load study, by rate class, as part of its long-standing load research program.

"Net Metering" customers were eligible for selection as sample sites; however, "Net Metering" was not used as a criteria for selecting sample sites.

The sample data used is the most representative currently available data to date.

PUC 5-3

Request:

3 (referencing PUC 4-5)

- Subpart (d): the Commission asked what value National Grid uses for the NLD Adjustment Factor when estimating ICAP tags, and how that value is calculated. National Grid explained how it's calculated, but did not provide the numerical value. Please provide the actual numerical value for the NLD Adjustment Factor. If this value changes over time, please provide a table of historic NLD Adjustment Factors.

- Subpart (e): the Commission asked how National Grid calculates "class average peak kW" values (used in estimating ICAP tags) for customer classes without interval data, using what specific billing data. Grid responded with a conceptual definition of "class average peak kW" but did not answer how it is calculated nor what specific data is used to perform such calculations. Please answer the question in full.

- Subpart (f): the Commission asked whether National Grid has the necessary interval data to calculate individual customers' ICAP tags, for each customer class. National Grid responded that if the Company does not have the necessary interval data for a class, it uses load shaped data instead. This does not answer the original question. Please specify whether, for each customer class, National Grid has the necessary interval data to calculate individual customers' ICAP tags.

- Subpart (g): the Commission asked how Grid estimates the ICAP tag for an SOS Group (as a whole) that contains at least one customer class where interval data is available and at least one customer class where it is not. In writing this question, the Commission wanted to know whether a single ICAP tag is estimated for the sum of all customers in the Group, or whether the group ICAP tag is a hybrid of class average ICAP (for the classes without interval data) and individual customer ICAPs (for the classes with interval data). National Grid's response did not answer this question. Please answer in full.

Response:

Subpart (d): From 2018 through 2020 the NLD factor had ranged from 1.06256 to 1.01997.

	6/1/2018	6/1/2019	6/1/2020
4005	1.06256	1.03944	1.01997

Prepared by or under the supervision of: John Maupin

Subpart (e): For customers without interval meter data available, the Company applies the respective Class Average Load Shape (which is based on a representative sample). The usage during the peak hour is obtained from the load shapes to represent the typical usage at the peak for that customer's rate class. Each non-interval customer's total monthly usage is compared to the average total monthly usage for that customer's rate class by taking the ratio of the customer's usage over the average usage for the rate class. The ratio is then multiplied against the load shaped usage during the peak hour to scale the customer's ICAP tag up or down by a factor proportionate to the amount that customer's total monthly usage was above or below the average total monthly usage for customers of that same rate class. This is how the monthly total usage for each customer is translated into a single hour ICAP value.

Subpart (f): The customers with interval meters have their ICAP tag calculated based off their interval meter data if available, while the customers without interval meters have their ICAP tag calculated from actual billing data from the monthly billed kWh during the peak month along with load research data. All Rate G-32 customers have interval meters; Rate G-02, A-16, A-32, and C-06 customers have only non-interval meters and therefor use actual metered data during the month of the peak. Each customer gets an individual ICAP tag calculation whether they have an interval or non-interval meter.

Subpart (g): ICAP tags for the SOS Commercial Group is a hybrid, where if available we use the customer interval data to calculate an ICAP tag (Rate G-02), and the other rate class's (Rate C-06) customers receive a load shaped ICAP tag from the annual Load Research shape study. The Company would add up all the customers' ICAP tag values to get a total value for the group, which is how the total ICAP capacity for the Commercial Group is derived.

Prepared by or under the supervision of: John Maupin

PUC 5-4

Request:

5-4 (referencing PUC 4-12)

- Subpart (a): the Commission asked how National Grid estimates "Class 12CP" values for the purposes of calculating Coincident Peak Allocators used in setting transmission rates, and with what billing data. National Grid provided a general estimation methodology, which includes (among other things) multiplying their customer counts by a "Class Average Load Shape CP Value." However, Grid did not explain what this "Class Average Load Shape CP Value" is, or what billing data it is based on. Please answer in full.

Response:

National Grid defines the "Class Average Load Shape" to be the estimated hourly loads for the "Typical Customer" in each class.

For Rate G-32, the estimated hourly loads for the "Typical Customer" are computed using the actual interval data collected each month from all Rate G-32 customers.

For the remaining rate classes, the estimated hourly loads for the "Typical Customer" are computed based on Load Research Sample Meter interval data. National Grid uses industry standard statistical modeling techniques to develop the estimated hourly loads for the "Typical Customer" from the Sample Meter interval data.

For all rate classes, National Grid computes the total estimated hourly loads for the rate class by multiplying the estimated hourly loads for the "Typical Customer" by the total number of customers for that rate class. The source data for the total number of customers in each rate class does not differentiate according to Net Metering status.

PUC 5-5

Request:

(referencing PUC 4-1):

o Subpart (c): National Grid responded that it uses "historical [PV] data… from the Company's tracking databases" to adjust its kWh sales forecasts for behind-the-meter net metering facilities.

- What specific "historical [PV] data from the Company's tracking databases" is incorporated in setting the next year's kWh forecast?
- Are these real meter reads from customers with behind-the-meter net metering (BTM) facilities?
- Are the load reduction estimates based on real nameplate capacity installed to-date?
- Please explain all of the responses.

o Subpart (d): Please explain why National Grid "not differentiate between net metering installations behind a specific customer's meter [BTM] and those located in front of those meters [FTM]" when adjusting its kWh forecasts for net metering.

- How does Grid reconcile this uniform load reduction accounting methodology with the physical reality that the load-offsetting potential of BTM NEM is different than FTM NEM?
- Does this mean that 100% of the output of FTM NEM facilities is subtracted from the annual kWh sales forecast?

Response:

Subpart (c):

- The nameplate capacity in MW (AC) for each installed PV is the specific data used from the Company's Interconnection Application tracking database. This database contains information on both installed and pending projects.
- No, these are not real meter reads.

- Yes, the load reduction estimates apply a monthly load factor to the installed nameplate capacity to derive the monthly kwh reductions. This information is based on information from the ISO-NE Distributed Generation Working Group (DGWG). The Company has included the monthly capacity factors that it uses in PUC 5-5 Attachment 1.

Subpart (d):

- In the historical dataset, the CSS kWh sales dataset, generation associated with both FTM and exported energy for BTM NM did not lower sales. However, future projections did not differentiate between BTM and FTM NM because at the time that the forecast was created FTM did not constitute a major share of all PV installations. The Company will revisit this during the next forecast cycle.

- As discussed in the bullet above, FTM NEM facilities were not included in the historical sales, but will be included in the future to create the forecast.

DG	Month	CF
PV	1	0.070
PV	2	0.075
PV	3	0.150
PV	4	0.195
PV	5	0.190
PV	6	0.225
PV	7	0.215
PV	8	0.205
PV	9	0.190
PV	10	0.120
PV	11	0.090
PV	12	0.060

PUC 5-6

Request:

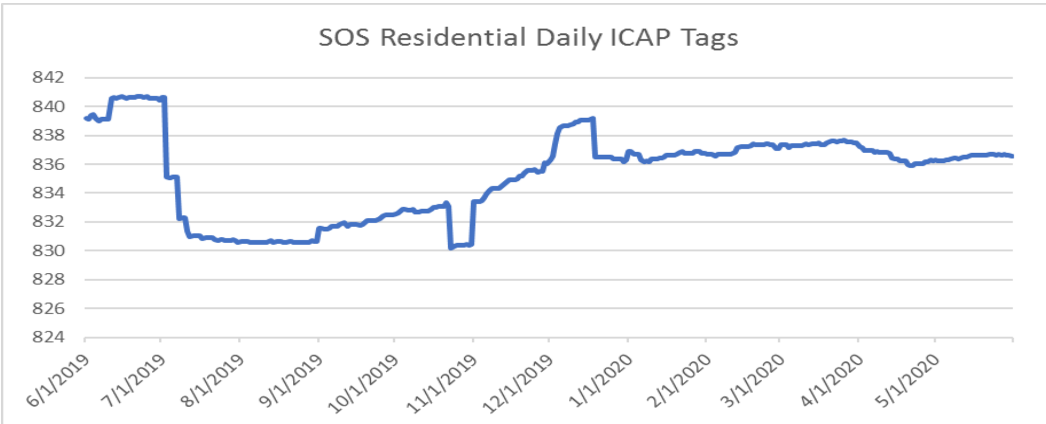
(referencing PUC 4-6)

- Subpart (a): Please clarify whether National Grid's response indicates that Grid is invoiced for capacity charges from Full Requirement Services suppliers on a monthly basis or an annual basis.
    - If the answer is monthly, please explain how the capacity charge (reflective of annual peak demand) is assessed on a monthly basis.
    - Is the capacity charge assessed to Grid for a given capacity year (based on its Capacity Load Obligation) simply divided by 12 to arrive at the monthly capacity charges?

Response:

Each month, the ISO-New England Inc. (ISO-NE) invoices Full Requirement Services suppliers for the capacity that corresponds to the bid blocks that they serve. These suppliers then invoice National Grid each month in order to pass through the net Forward Capacity Market (FCM) charges. Monthly capacity charges are not the annual capacity costs divided by 12 because some of the inputs in the ISO-NE net FCM charge settlement calculation change monthly.

The Customer Average Peak Contribution (also known as the ICAP tags) is determined by the load coincident with the ISO-NE system peak in the prior calendar year. While the Customer Average Peak Contribution for all National Grid distribution load is the same throughout a given capacity year, the Customer Peak Contribution fluctuates daily for each load asset as customers migrate to and from Standard Offer Service. The following graph illustrates the daily ICAP tags fluctuations for the Standard Offer Service Residential Group:



The ISO-NE averages the daily Peak Contributions in a month to determine the Customer Average Peak Contribution for a month. Therefore, the net FCM charge from the ISO-NE changes monthly throughout a given capacity year because the Customer Average Peak Contribution changes. Several other inputs in the net FCM settlement calculation change monthly. For example, the Net Regional Clearing Price changes each month:[1]

Month	Capacity Zone	Net Regional Clearing Price ($/kW-month)
Jul-20	Southeast New England	$7.940111
Aug-20	Southeast New England	$7.979772
Sep-20	Southeast New England	$7.927191
Oct-20	Southeast New England	$7.772104
Nov-20	Southeast New England	$7.777614
Dec-20	Southeast New England	$7.925424
Jan-20	Southeast New England	$8.115115
Feb-20	Southeast New England	$8.114029
Mar-20	Southeast New England	$8.112889
Apr-20	Southeast New England	$7.810881
May-20	Southeast New England	$7.763100
Jun-20	Southeast New England	$6.743726
Jul-20	Southeast New England	$6.750267

[1] Reproduced from the Monthly Market Operations Report July 2020, page 51, available at: https://www.iso-ne.com/static-assets/documents/2020/08/2020_07_mnthly_market_rpt.pdf.

PUC 5-7

Request:

(referencing PUC 4-11)

- Subpart (a): in this question, the Commission was seeking an estimate of the incremental cost to National Grid of serving a severe storm in Rhode Island. Recognizing the challenge of providing a singular "incremental cost" estimate, please supplement your response with a table listing the total annual costs ($) allocated to the Storm Fund each year dating as far back as your records allow.

Response:

Please see PUC 5-7 Attachment 1 for the information requested, which appears in Microsoft Excel format. The Company has provided readily available information from January 1999 through May 2020.

PUC 5-8

Request:

(referencing PUC 4-13)

- Subparts (a) and (b): In subpart a, National Grid responded that its Regional Network Load for a given month is its "hourly load… with the coincident load of all network customers served in each Local Network in the hour in which the coincident load is at its maximum for the month." In subpart (b), National Grid responded that its Regional Network Load is "metered data at the time of National Grid's monthly system peak."
  - Please reconcile the difference in the 2 responses. In other words, is Grid's monthly Regional Network Load (against which it is assessed PTF transmission charges) its own monthly system peak or its hourly peak at the time of "the coincident aggregate load of all network customers"?
- Subpart (d): the Commission originally asked how "monthly PTF kW load" values are adjusted for load reduction from BTM NEM. Can Grid please clarify whether their response that "no adjustments [are] made to monthly PTF kW load values due to the load reduction effect of net metering" is true of BTM NEM only, or both BTM and FTM NEM.
  - If the response is only true of BTM NEM, please clarify how monthly PTF kW load values are adjusted for load reduction from FTM NEM.

Response:

To clarify the original response around Regional Network Load, it is National Grid's own monthly system peak.

The same response holds for FTM NEM as BTM NEM in that both FTM and BTM NEM are not reconstituted in Regional Network Load.

Prepared by or under the supervision of: Michael V. Artuso