Andrew S. Marcaccio
Senior Counsel

April 1, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5234 – 2022 Annual Retail Rate Filing
<u>Responses to PUC Post-Hearing Data Requests – Set 1 (Complete Set)</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed, please find the electronic version of the Company's complete set responses to the First Set of Post-Hearing Data Requests issued by the Public Utilities Commission ("PUC") in the above-referenced docket.[1]

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5234 Service List
John Bell, Division
Al Mancini, Division
Tiffany Parenteau, Esq.
Greg Schultz, Esq.

[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________ April 1, 2022
Joanne M. Scanlon Date

National Grid – 2022 Annual Retail Rate Filing - Docket No. 5234
Service List Updated 2/23/2022

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PUC Post-Hearing 4-1

Request:

Please provide a copy of the correction made to the pre-filed testimony (Bates 249) of Alexi Spinu at hearing on March 23, 2022.

Response:

Please see Attachment PUC 4-1 for the correction made to the pre-filed testimony. This correction is highlighted on page 18.

Prepared by or under the supervision of: Vishal Ahirrao and Alexei Spinu

THE NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID
RIPUC DOCKET NO. 5234
2022 ANNUAL RETAIL RATE FILING
WITNESS: ALEXEI SPINU

PRE-FILED DIRECT TESTIMONY

OF

ALEXEI SPINU

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I. <u>Introduction and Qualifications</u>

Q. Please state your name and business address.

A. My name is Alexei Spinu. My business address is 40 Sylvan Rd, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I currently hold the position of Senior Analyst in Strategy & Regulation for National Grid USA Service Company, Inc. ("Service Co"). Service Co. is a subsidiary of National Grid USA. My duties include performing rate-related services for The Narragansett Electric Company ("Narragansett" or the "Company"), Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid.

Q. Please describe your educational and professional background.

A. I graduated from Wheaton College in Norton, Massachusetts with Bachelor of Science degrees in Economics, and Business & Management. I have been with National Grid USA for four years. As a Senior Analyst in the Strategy & Regulation department, I am involved in Narraganset Electric and Massachusetts Electric transmission-related calculations impacting the Company, including supporting the Company's current Transmission Service Cost Adjustment before the Rhode Island Public Utilities Commission (the "Commission").

Q. Have you previously testified before the Commission?

A. No.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's estimated 2022 transmission expenses, including administrative expenses charged to the Company by ISO New England Inc ("ISO-NE"). First, I will summarize the various transmission services provided to Narragansett and how Narragansett pays for such services. Second, I will provide testimony supporting the forecast of transmission expenses that Narragansett expects to incur in 2022, which is summarized in Schedule AS-2. As described more fully in the second part of my testimony, the Company expects that there will be an increase of $10,494,532 in prospective transmission expenses compared to the forecast provided for calendar year 2021 in PUC Docket No. 5127.

III. <u>Summary of Transmission Services Provided to Narragansett</u>

Q. Please explain the history of transmission service provided to Narragansett under rate schedules approved by the Federal Energy Regulatory Commission ("FERC").

A. Effective January 1, 1998, Narragansett began receiving transmission services on behalf of its entire customer base, under two tariffs: NEPOOL's FERC Electric Tariff No. 1 ("NEPOOL Tariff") and New England Power Company's ("NEP's") FERC Electric

Tariff No. 9 ("NEP T-9 Tariff"). Additionally, effective January 1, 1999, Narragansett began taking service under ISO-NE's FERC Electric Tariff No. 1 ("ISO-NE Tariff").

Effective February 1, 2005, FERC issued an order authorizing ISO-NE to begin operating as a Regional Transmission Organization ("RTO"), and at that time, ISO-NE replaced NEPOOL as the transmission provider in New England. The new ISO-NE Transmission, Markets and Services Tariff ("ISO/RTO Tariff") replaced the three separate tariffs referred to above by aggregating them into a single, omnibus tariff. As a result, NEP and ISO-NE as the RTO now charge Narragansett under the ISO/RTO Tariff.

Therefore, the prospective charges to the Company are separately identified as (1) NEP local charges, (2) ISO-NE regional charges, and (3) ISO-NE administrative charges.

Q. Please describe further the types of transmission services that are billed to Narragansett under the ISO/RTO Tariff.

A. New England's transmission rates utilize a highway/local pricing structure. Under this structure, Narragansett receives regional transmission service over "highway" transmission facilities under Section II of the ISO/RTO Tariff and receives local transmission service over local transmission facilities under Schedule 21 of the ISO/RTO Tariff. Additionally, ISO-NE provides transmission scheduling and market administration services under Section IV.A of the ISO/RTO Tariff.

<u>Explanation of ISO/RTO Tariff Services, Rates, and Charges</u>

Q. Please explain the services provided to Narragansett under the ISO/RTO Tariff.

A. Section II of the ISO/RTO Tariff provides access over New England's looped transmission facilities, more commonly known as Pool Transmission Facilities ("PTF") or bulk transmission facilities. These facilities serve as New England's electric transmission "highway", and the service provided over these facilities is referred to as Regional Network Service ("RNS"). In addition, as described in detail later in this testimony, the ISO/RTO Tariff provides for Blackstart, Reactive Power, Scheduling, System Control, and Dispatch and Administrative Services.

Q. How are the costs for RNS recovered?

A. The ISO-NE RNS Rate ("RNS Rate") recovers the aggregate revenue requirement for certain PTF facilities owned by NETOs. The RNS Rate is determined annually in accordance with a FERC-approved formula. Pursuant to a NEPOOL Settlement dated April 7, 1999, which was incorporated into the ISO/RTO Tariff, the RNS Rate has transitioned from zonal rates to a single, "postage stamp" rate in New England.

On June 15, 2020, the New England Transmission Owners (NETOs) filed a Joint Offer of Settlement (Settlement) addressing the NETOs' local and regional transmission service revenue requirement formula rate(s) in the ISO New England Inc. (ISO-NE) Open Access Transmission Tariff which were the subject of a FERC initiated proceeding in

Docket No. EL16-19. On December 28, 2020, FERC approved the Settlement, which was docketed as ER20-2054-000. This settlement resolved all issues that were set for hearing in Docket No. EL16-19. As part of this settlement, the design and implementation of the RNS and LNS rates were synchronized. The changes are detailed below in section III. The effective date of the settled formula rate is January 1, 2022.

Q. Please describe the ISO-NE Blackstart, Reactive Power and Scheduling, System Control and Dispatch Services that are included in the ISO/RTO Tariff.

A. ISO-NE Blackstart Service, also known as System Restoration and Planning Service from Generators, is necessary to ensure the continued reliable operation of the New England transmission system. This service allows for the designation of generators with the capability of supplying load and ability to start without an outside electrical supply to re-energize the transmission system following a system-wide blackout.

Reactive Power Service, also known as Reactive Supply and Voltage Control from Generation Sources Service, is necessary to maintain transmission voltages on the ISO-NE transmission system within acceptable limits and requires that generation facilities be operated to produce or absorb reactive power. This service must be provided for each transaction on the ISO-NE transmission system. The amount of reactive power support that must be supplied for transactions is based on the support necessary to maintain transmission voltages within limits generally accepted and is consistently sustained in the region.

Finally, Scheduling, System Control, and Dispatch Service ("Scheduling & Dispatch Service") includes the services required to schedule the movement of power through, out of, within, or into the ISO-NE Control Area over the PTF and to maintain system control. Scheduling & Dispatch Service also provides for the recovery of certain charges that reflect expenses incurred in the operation of satellite dispatch centers.

Q. How are the ISO-NE charges for Blackstart and Reactive Power services charged to Narragansett?

A. Each month, ISO-NE assesses charges for Blackstart and Reactive Power services to Narragansett based on Narragansett's proportionate share of the Regional Network Load to ISO-NE's total Regional Network Load. The monthly Blackstart charge includes Critical Infrastructure Protection ("CIP") payments applicable to Blackstart generators. CIP payments are made to existing Blackstart generators based upon proxy costs in compliance with the CIP standards of the North American Electric Reliability Corporation (NERC). Blackstart CIP payments are applicable to Blackstart generators that are designated by ISO-NE as Northeast Power Coordinating Council ("NPCC") Key Facilities and provide annual confirmation to the ISO that they are incurring CIP-related costs. The allocation of ISO-NE's total Blackstart CIP costs to Narragansett is based similarly on

Narragansett's proportionate share of the total Regional Network Load. The monthly Reactive Power charge includes payments to generators that are dispatched down by, or at the request of, the ISO-NE, or a local control center for the purpose of providing Reactive Power service. Generators that provide Reactive Supply service to the transmission system are compensated by different mechanisms pursuant to Section II.4 and Schedule 2 of the ISO/RTO Tariff. The hourly charges for Reactive Power service to generators are allocated to Narragansett based on its proportionate share of the total Regional Network Load and Reserved Capacity.

Q. How are the charges for Scheduling & Dispatch Service charged to Narragansett?

A. Charges for Scheduling & Dispatch Service are based on the expenses ISO-NE incurs and by the individual transmission owners in the operation of local control dispatch centers or otherwise to provide Scheduling & Dispatch Service.

The expenses that ISO-NE incurs to provide these services are recovered under Section IV.A, Schedule 1 of the ISO/RTO Tariff. These costs are allocated to Narragansett each month based on the FERC-approved fixed rate for the month multiplied by Narragansett's monthly Regional Network Load.

The aggregate costs that NETOs incur to provide Scheduling & Dispatch Service over PTF facilities, including the costs of operating local control centers, are recovered under

Section II, Schedule 1 of the ISO/RTO Tariff. These costs are allocated to Narragansett each month based on a formula rate that is determined each year based on the prior year's costs incurred multiplied by Narragansett's monthly Regional Network Load.

The costs of Scheduling & Dispatch Service that the individual transmission owners incur for transmission service over transmission facilities other than PTF are charged under Schedule 21 of the ISO/RTO Tariff. Thus, there are three types of Scheduling & Dispatch Service costs that are similar, but which are charged to Narragansett through three different tariff mechanisms.

Q. What administrative services and/or charges flow through to Narragansett under Section IV.A of the ISO/RTO Tariff?

A. There are five different charges billed to Narragansett under Section IV.A of the ISO/RTO Tariff under Schedule 1, Schedule 2, Schedule 3, Schedule 4, and Schedule 5. As described above, Schedule 1 provides for one component of the administration of Scheduling & Dispatch. Schedule 2, Energy Administrative Service, includes the core operation of the energy market, generation dispatch, and energy accounting. Schedule 3, Reliability Administrative Service, administers the reliability markets and provides other reliability and informational services. Schedule 4 of the ISO/RTO Tariff provides for the collection of FERC Annual Charges. Under Schedule 5, ISO-NE acts as the billing and collection agent for the New England States Committee on Electricity's ("NESCOEs") annual budget.

Q. Please explain the background for the inclusion of the NESCOE charges under Schedule 5 of the ISO/RTO Tariff, Section IV.A.

A. NESCOE was established by a memorandum of understanding between ISO-NE and NEPOOL and approved by FERC for funding through the ISO/RTO Tariff in the Fall of 2007. NESCOE created a formal role for the six New England states' participation on an ongoing basis in the decision-making process of the RTO. NESCOE represents the policy perspectives of the New England Governors and their collective interests in promoting a regional electric system that ensures the lowest reasonable long-term costs for customers while maintaining reliable service and environmental quality.

Q. How are the administrative charges under Section IV.A. of the ISO/RTO Tariff assessed?

A. With the exception of charges under Schedule 4, ISO-NE assesses the charges in Section IV.A based upon stated rates pursuant to the ISO/RTO Tariff. These stated rates are set annually when ISO-NE files a revised budget and cost allocation proposal to become effective on January 1 of each year. Under Schedule 1 and Schedule 5, the stated rate for these services is multiplied by Narragansett's Regional Network Load as part of ISO-NE's monthly billing process.

The ISO-NE budget and cost allocation proposal filed October 15, 2021 reported the total fiscal year 2022 NESCOE budget at $2,485,156 which was offset by a credit true-up for actual costs and collections in prior years of $781,042 for the total net NESCOE Revenue Requirement of $1,704,114. As a result, NESCOE's per KW/month charge is set at $0.00736.

The ISO-NE budget and cost allocation proposal filed on October 15, 2021 reported the net revenue requirement for Schedule 1 totaling $44,381,680 after the true-up. As a result, ISO-NE's Schedule 1 rate was set at $0.19175 per KW/month for all regional network customers and at $0.00026 per KW for each hour of service for transmission customers receiving through or out service.

The allocation of Schedule 2 charges is based upon various billing units. The rates under ISO Schedule 2 are adjusted annually effective January 1 of each year based on the net revenue requirement. The 2022 net revenue requirement for Schedule 2 is $106,153,680 after the true-up. Charges assessed to the Company under ISO-NE's Schedule 2 are recovered through the Standard Offer Service charge and base distribution rates depending on the type of transaction.

Schedule 3 charges for Market Participants are based on the participant's real-time non-coincident peak load obligation (Real-Time NCP Load Obligation) for the month. Market

Participants who have exports will be charged based on their hourly scheduled Megawatts of exports in the month. The rates under ISO-NE's Schedule 3 are adjusted annually effective January 1 of each year based on the net revenue requirement. The 2022 net revenue requirement for Schedule 3 is $65,607,211 after the true-up. The 2022 Real-Time NCP Load Obligation rate is $0.24962 per kilowatt-month. The 2022 export rate is $0.53 per MWh.

Schedule 4 charges are based upon FERC's total assessment to the New England Control Area and are directly assessed to NEP based on its proportion of total MWhs of transmission (including Narragansett's) to the total of the New England Control Areas' total MWhs. NEP, in turn, allocates a portion of the charges received under Schedule 4 to Narragansett through a combination of RNS and LNS rates. A portion is charged to Narragansett by the ISO-NE through the RNS rate using the transmission plant allocation factor and remitted to NEP based on a pro-rate share basis. NEP charges the remaining amounts to the Company through the monthly Non-PTF Demand charge.

<u>Explanation of Local NEP Services and Charges</u>

Q. What services are provided to Narragansett under Schedule 21-NEP of the ISO/RTO Tariff?

A. Schedule 21-NEP provides service over NEP's local, non-highway transmission facilities, also known as Non-PTF facilities ("Non-PTF"). The service provided over

Non-PTF is referred to as Local Network Service ("LNS"). NEP also provides metering, transformation and certain ancillary services ("Other NEP Charges") to Narragansett to the extent that such services are required by Narragansett and not provided under Section II the ISO/RTO Tariff.

Q. Please explain the components of "Other NEP Charges" to Narragansett under Schedule 21.

A. Other NEP Charges are comprised of Scheduling and Dispatch charges and Transformer and Meter Surcharges. Each component is explained below.

Scheduling and Dispatch charges are services required to schedule the movement of power through, out of, within, or into the ISO-NE Control Area over Non-PTF. Narragansett purchases this service from NEP. Such charges to Narragansett are charged through the Local Load Dispatch Surcharge. The Local Load Dispatch Surcharge is equal to the Company's monthly PTF load multiplied by the Monthly Local Network Load Dispatch Surcharge Rate as per Exhibit 5 to NEP's Schedule 21-NEP.

NEP provides transformation service when a customer uses NEP-owned transformation facilities to step down voltages from 69 kV or greater to a distribution voltage. NEP provides metering service when a customer uses NEP-owned meter equipment to measure the delivery of transmission service. NEP separately surcharges the appropriate customers for these services.

Q. Please explain the BITS Surcharge to Narragansett under Schedule 21.

A. The Block Island Transmission System ("BITS") Surcharge is another NEP charge to Narragansett approved by the FERC under Schedule-21-NEP of the ISO/RTO Tariff. The BITS Surcharge recovers Narragansett's allocated share of the costs for the Block Island Cable and related facilities associated with the Town of New Shoreham Project. The Town of New Shoreham Project is a public policy project authorized and directed by Rhode Island law, which provides that:

> "it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland."[1]

The legislation also directs that the annual costs of these facilities "shall be recovered annually through a fully reconciling rate adjustment from customers of the electric distribution company [Narragansett] and/or from the Block Island Power Company ("BIPCO") or its successor, subject to any federal approvals that may be required by law." R.I. Gen. Laws § 39-26.1-7(f). Under the currently effective Schedule 21-NEP of

[1] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7(a). (Supp. 2010).

the ISO/RTO Tariff, the BITS Surcharge to Narragansett is equal to the integrated facilities credit paid to Narragansett under NEP's FERC Electric Tariff No. 1 ("IFA Facilities Credit") multiplied by Narragansett's Load Share Percentage.

For purposes of preparing the 2022 forecast, the BITS Surcharge was calculated based on the amended formula filed at FERC on 12/22/2021 in docket ER22-707-000. The amendment is currently awaiting FERC approval and if approved will take effect 1/1/2022. The proposed formula for calculating the BITS Surcharge to Narragansett is equal to 1/12th of the product of the integrated facilities credit paid to Narragansett under NEP's FERC Electric Tariff No. 1 ("IFA Facilities Credit") multiplied by Narragansett's Load Share Percentage, where the IFA Facilities Credit is equal to the sum of the following:

a. Integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1, excluding (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, and (G) Primary Related Administrative and General Expense;

b. Actual BITS specific Municipal Tax Expense;

c. Actual BITS specific Operation and Maintenance Expense; and

d. 2.5% of Total Primary Related Administrative and General Expense.

Narragansett's Load Share Percentage will be equal to 1 minus BIPCO's Load Share Percentage calculated based on the load data for the prior year. The IFA Facilities Credit amount will be updated annually on or about the June billing month of each year. The estimated monthly BITS surcharge amounts are calculated in Schedule AS-8.

The Block Island Cable was placed in commercial service on October 31, 2016 when it began providing station service to the Block Island Wind Farm. Effective as of November 1, 2016, NEP began charging the BITS Surcharge to Narragansett and BIPCO in accordance with the transmission tariffs and service agreements that have been accepted by FERC for this purpose. In turn, Narragansett's costs are being passed through its Transmission Service Cost Adjustment to its retail customers.

Q. How are the costs for LNS recovered?

A. Effective January 1, 2022, pursuant to the terms of the total comprehensive settlement approved by the Commission in Docket No. ER20-2054, the RNS and LNS revenue requirement will be calculated in accordance with the formula rate included in Attachment F of the ISO-NE OATT. The fully synchronized rates will be a stated ($/kW-month) annual rate subject to true up to actual costs.

Explanation of Changes to new RNS & LNS Rate Design

Q. What change(s) were made to the RNS & LNS rate design?

A. Settling parties agreed to replace the existing regional and local formula rates under the ISO-NE OATT with a new formula that is based on spreadsheets (or templates) that are similar to the formula rates recently accepted by the Commission and used by other transmission-owning public utilities. The new templates set forth the methodology for calculating each cost component of the rate and provide complete transparency about the method of calculation and the source of the data.

The existing rate structure, in which each PTO has its own PTO-specific formula rate for Local Network Service (in Schedule 21 of the ISO-NE OATT), is replaced with a single formula rate that applies to all PTO transmission facilities and associated costs. The current distinction between regional costs (i.e., costs for Pool Transmission Facilities or "PTF") and local costs is maintained for cost allocation purposes. Under the settlement, Regional Service rates will be based on the costs of Pool-Supported PTF, which will be allocated and recovered in Regional Service rates. Non-PTF costs will be allocated and recovered from each PTO's local customers. The use of a single formula rate that applies to all PTO transmission facilities and associated costs addresses concerns in the December 2015 Order about synchronization between regional and local rates.

Q. What change(s) were made to the load dispatching rates?

A. There are no changes to the ISO-NE's Regional Scheduling & Dispatch Service. The Local Scheduling & Dispatch Service rate will be aligned with the Regional rate by moving from a monthly calculation to an annual rate effective June 1st thru May 31st of the following year. For purposes of the initial transition, the Local Scheduling & Dispatch Service rate will be calculated to coincide with the effective date of the new RNS & LNS tariff on January 1st and will reset June 1st.

Q. What is the financial impact as a result of the new rate design?

A. As per the Explanatory Statement in the Settlement Agreement, none of the changes made to the settled formula rate result in any material change to the revenue requirement for any Indicated New England Transmission Owner or in any material rate increase to ratepayers.

IV. Estimated Transmission Expenses

Q. What is the forecast for Narragansett's transmission and ISO expenses for 2021?

A. Narragansett estimates that its total transmission and ISO-NE expenses (including certain ancillary services) for 2022 will be approximately $232.59 million, as shown in Schedule AS-2, page 1. This equates to an increase of $10.50 million or 4.73% of the estimated expenses underlying Narragansett's 2021 transmission rates, as shown in Schedule AS-2, page 2.

Q. Have you estimated the Local NEP Charges to Narragansett under Schedule 21 of the ISO/RTO Tariff?

A. Yes. Lines 1 through 3 of Schedule AS-2, page 1, show the amount of forecasted NEP local charges. The total amount of expenses is $53.10 million. Schedule AS-7 shows the calculation of the total NEP revenue requirement. NEP charges Non-PTF expenses to Narragansett by multiplying the Company's Non-PTF Load by the NEP's Monthly Local Network Service Rate in effect at the time as shown in Exhibit AS-6, column (1). Metering and transformation charges are based on current rates and are assessed to Narragansett based on a per meter and peak load basis, respectively. The BITS Surcharge billed to Narragansett for the period April 2022 through March 2023 is an estimated total of approximately $10.52 million. The calculation of the monthly BITS Surcharge shown on Schedule AS-8 was based on the sum of Primary related Return, actual municipal tax expenses, actual Operations and Maintenance expenses, and a 2.5% fixed BITS related Administration and General Expense. The estimated BITS Surcharge total is allocated based on Narragansett's Load Share Percentage of approximately 99.71%, that is calculated on calendar year 2021 load data, divided by 12.

The Primary related Return is a product of the estimated monthly gross plant investment multiplied by Narragansett's primary distribution carrying charge of 6.50%, adjusted to exclude Primary Related Municipal Tax Expense, Operation and Maintenance Expense, and Administration and General Expenses.

The actual BITS Administration and General Expenses is calculated as a product of 2.50% times the Primary related Administration and General Expenses, where 2.50% is fixed per the revised Attachment 2 of TSA-NEP-86, and Attachment 1 of TSA-NEP-83 which is pending FERC approval as discussed previously.

Q. How have the PTF Component of the ISO-NE Regional Charges shown on line 4 of Schedule AS-2, page 1 been forecasted?

A. The PTF Component of ISO-NE Regional Charges shown on line 4 of Schedule AS-2, page 1 have been forecasted using two components: 1) the most recent 12 months of monthly PTF kW Load per the Monthly Regional Network Load Report posted on the ISO-NE website; and 2) actual and forecasted annual RNS rates for the respective months. The monthly load is multiplied by the annual rate and divided by 12 to obtain the monthly PTF Demand Charge. The resulting calculation is shown in column 2 of Schedule AS-3, page 1.

For the most recent 12 months of PTF kW Load, the period of January through December 2021 was used. For the estimated PTF rate, two different rates have been utilized (see Schedule AS-4). For April 2022 to December 2022, the actual annual rate effective for this period of $142.78 was used. The calculation of the estimated 2023 PTF rate on line 8 of Schedule AS-4 was based on the forecasted Regional System Planning, and Asset Conditioning list provided by ISO-NE, ISO-NE . The estimated RNS Rate for January 2023- March 2023 was calculated using the estimated New England transmission owners' plant additions of $551.7 million and equals the forecasted annual rate of $147.09. Narragansett's PTF Demand Charge is estimated at approximately $170.84 million.

Q. Schedule AS-2 also includes estimated ISO-NE charges for Scheduling and Dispatch. How were these costs forecasted, as shown?

A. The estimate for Scheduling and Dispatch Service as shown in column (3) of Schedule AS-3, page 1, was derived by using the currently effective ISO/RTO Tariff Schedule 1 rate of $1.86858 per kW-year, divided by 12, and further multiplied by Narragansett's monthly Regional Network Load, as shown in column (1) of Schedule AS-3, page 1. The Company estimates that it will receive an allocation of $2.22 million for 2022.

Q. How did you forecast the Blackstart costs shown on line 6 of Schedule AS-2, page 1?

A. The Blackstart costs shown on line 6 of Schedule AS-2, page 1, were forecasted based on the most recent 12 months of actual ISO-NE charges to the Company. Using this methodology, the Company estimates that it will receive an allocation of $2.15 million for 2022.

Q. How did you calculate the estimate for Reactive Power costs for Narragansett as shown on line 7 of Schedule AS-2, page 1?

A. The estimated Reactive Power cost for the New England region was calculated by using the January through December 2021 actual ISO-NE settlement reports, as shown on Schedule AS-5 (line 1). The annual rate was determined by adding 12 months' worth of Reactive Power VAR units, which represents a unit of measure of Reactive Power, taken from the monthly ISO-NE VAR reports. The 12-month total is then multiplied by the 2022 monthly Reactive Power Rate obtained from the ISO-NE website, and then further divided by the ISO-NE's 2020 Regional Network Load. The monthly rate (annual rate divided by 12) was then multiplied by Narragansett's monthly Regional Network Load for the period of January through December 2021 to determine the estimated charges for Reactive Power Service. Using this methodology, the Company estimates that it will receive an allocation of $1.26 million for 2022.

Q. Please explain the forecast of the ISO-NE charges shown in lines 8 through 10 of Schedule AS-2, page 1.

A. Line 8 of Schedule AS-2, page 1, shows the 2022 forecast of charges to Narragansett under Schedule 1, Scheduling and Load Dispatch Administrative schedules through Section IV.A of the ISO/RTO Tariff. The estimate is based on the ISO-NE revenue requirement for Schedule 1 filed each year with FERC. ISO-NE filed its proposed 2022 revenue requirement with FERC on October 15, 2021. To estimate Narragansett's 2022 ISO-NE Schedule 1 charges, ISO-NE's Schedule 1 actual costs for the periods December 2020 through November 2021 are adjusted by an inflationary factor shown on line 16 of Schedule AS-3, page 2. This inflationary factor is intended to recognize the increase or decrease in ISO-NE's Schedule 1 net revenue requirement and the associated components of that revenue requirement from the budget as filed for the previous year.

Line 9 of Schedule AS-2, page 1 shows the estimated 2022 ISO Schedule 3 Reliability Administrative Service charges through Section IV.A of the ISO/RTO Tariff. The estimate is based on the ISO-NE Schedule 3 Real-Time Non-Coincidental Peak Load Obligation annual rate set each year by the ISO-NE. The annual rate was filed with ISO-NE Capital Budget and Revised Tariff Sheets for Recovery of 2022 Administrative Costs with FERC on October 15, 2021. The estimated 2022 charge to Narragansett's was calculated using the actual Narragansett's ISO Schedule 3 charges for the periods December 2020 through November 2021 adjusted by the inflationary factor shown on Line 19 of Schedule AS-3, page 2. The inflationary factor represents the change in the 2022 ISO Schedule 3 Non-Coincidental Peak Load Obligation rate from the previous year.

Line 10 of Schedule AS-2, page 1 shows the estimated 2021 NESCOE charges under Schedule 5 of Section IV.A of the ISO/RTO Tariff. For calendar year 2022, each customer that is obligated to pay the RNS rate pays each month an amount equal to the product of $0.00736/kW-month multiplied by its monthly Regional Network Load for that month. These charges are shown in Column (3) of Schedule AS-3, page 2.

For 2022, the Company's total amount of direct ISO/RTO Tariff charges under Section IV.A, Schedules 1, 3, and 5, are estimated to be $3.01 million.

Q. What is the sub-total of transmission expenses attributable to charges from the ISO-NE?

A. The sub-total of ISO-NE charges is $179.48 million, which is the sum of lines 4 through 10 on Schedule AS-2, page 1.

V. <u>Explanation of Primary Changes from Last Year's Forecasted Expenses</u>

Q. What is the impact of Narragansett's 2020 transmission expenses?

A. The estimated 2022 Narragansett transmission and ISO-NE expenses of $232.59 million represents a net increase of $10.50 million from the 2021 forecast of transmission expenses. This increase is primarily driven by a decrease in forecasted NEP charges of $(7.96) million which offsets increases in the forecasted ISO-NE PTF Demand Charge of $18.10 million. The increase in the forecasted ISO-NE Charges is primarily driven by a 6% increase in the Company's Regional Network Load driving an increase of $9.56

million. RNS rate increased by 5.12%, which is driving an increase of $7.79 million; this results in a $17.35 million increase in the forecasted PTF Demand Charge.

The decrease in the NEP Local charges is primarily driven by: 1) the increase estimated Non-PTF Demand charges resulting from a higher estimated Non-PTF revenue requirement in comparison to last year's Non-PTF revenue requirement, and 2) offset by a decrease in the forecasted BITS Surcharge. The decrease in the forecasted BITS surcharge is driven by the proposed change in the formula rate that incorporates actual expenses.

Q. Please further explain the increase in forecasted PTF component of the ISO-NE Regional Charges?

A. The $17.35m increase to the forecasted charges are driven by an increase in the following forecasted RNS rates from: 1) $129.26/KW-YR to $142.78/KW-YR for the period of April – May, 2) $138.37/KW-YR to $142.78/KW-YR for the period of June – December, and 3) $138.37/KW-YR to $147.09/KW-YR for periods of January to March. The increase in RNS resulted in a $7.79m increase in the forecasted PTF component, and a $9.56m increase due to a higher projected PTF kW load.

Q. What PTF plant investment is driving the increase in the ISO-NE RNS rate forecasted to be in effect June 1, 2021?

A. The projected RNS rate increase is due to a significant number of capital additions forecasted by the transmission owners to go into service in 2022. Exhibit AS-4 Line 4 shows an estimated $551.70 million of PTF plant additions for 2023 as provided by the ISO-NE, which is used to estimate 2023 RNS rate.

Q. What are the major projects driving the significant level of projected PTF plant additions for 2023?

A. Based on the October 2023 ISO-NE's Regional System Plan and Asset Condition List project listings, the five largest transmission projects in New England with a portion expected to be placed in service during 2023 are: Southeast Massachusetts / Rhode Island Reliability Project, Greater Boston North/Western projects, NH 2029 Solution reliability project, 110-510 & 110-511 lines 115 kV HPFF refurbishment, Copper Conductor and Shield Wire Replacement - Line 1231/1242, and Bourne Substation rebuild.

VI. Conclusion

Q. Does this conclude your testimony?

A. Yes.

PUC Post-Hearing 4-2

Request:

Referencing the response to PUC 3-6, page 2 of 5, please answer the following questions:

a. At the March 23, 2022 hearing, Mr. Gallagher explained that the resettlements for generation prior to CY21 of 660.4 on line 29, column (e) were priced at $279.94 per MWh as presented on line 29, column (g) – "Prior Period Contract Price".
   Is the above summary of Mr. Gallagher's testimony correct? Please explain your answer.
b. The contract price for CY20 was $270.47 and CY19 was $261.32. Therefore, it seems that the prior period generation cost was based on an incorrect contract price. Is the above conclusion that the prior period generation cost was calculated on an incorrect contract price correct? Please explain your answer.

Response:

Referencing the Company's response to PUC 3-6, Page 2, Line (29) Deepwater Wind Asset No. 38495, the 660.4 MWh listed in Column (e) as Resettlements for Generation prior to CY21 should've been included in Column (d) Actual Annual Output (MWh). Deepwater Wind had no Resettlements for Generation prior to CY21 and the 660.4 MWh was priced correctly at the CY21 Contract Price ($ per MWh) of $279.94.

PUC Post-Hearing 4-3

Request:

For what purposes does the Company use its retail deliveries forecast? Does the Company use the retail deliveries forecast in any other programs or for any other purposes? If yes, please describe how the forecast is used.

Response:

The Company uses its retail deliveries forecast to estimate revenues and expenses as well as to calculate rates based on an amount to be recovered from or credited to customers pursuant to the various tariff provisions under which the Company recovers costs from customers.
For example, in this proceeding, all approved rates are based on a forecast of retail deliveries to calculate the factors that will be billed to customers effective for usage on and after April 1, 2022 pursuant to the tariff provisions referenced in the pre-filed testimony provided by the Company. The Company uses the most recent kWh deliveries forecast available at the time of the filing for each of the factors/charges listed below in subparts (i) through (xxiv). One exception is the Base Transition Charge – subpart (xvii), which uses a forecast developed years ago and is sourced from the wholesale CTC reports that are submitted to the Public Utilities Commission and the Division of Public Utilities and Carriers. [1]

i. Capacity charge (unitized to a $/kWh rate), as included in the base LRS rate
ii. LRS Administrative Cost Factor
iii. LRS Adjustment Factor
iv. Base Distribution charge (per-kWh charge)
v. Operating and Maintenance Expense Charge
vi. Operating and Maintenance Reconciliation Factor
vii. CapEx Factor Charge (per-kWh charge)
viii. CapEx Reconciliation Factor
ix. RDM Adjustment Factor
x. Pension Adjustment Factor
xi. Storm Fund Replenishment Factor
xii. Arrearage Management Adjustment Factor
xiii. Low-Income Discount Recovery Factor
xiv. Base Transmission Charge (per-kWh charge)
xv. Transmission Adjustment Factor

[1] For additional information, please see the Company's response to PUC 4-1 in Docket No. 5010 http://www.ripuc.ri.gov/eventsactions/docket/5010-NGrid-DR-PUC4%20(08-12-2020).pdf and the Company's response to PUC 5-1 in Docket No. 5010 http://www.ripuc.ri.gov/eventsactions/docket/5010-NGrid-DR-PUC5%209-8-2020.pdf.

Prepared by or under the supervision of: Jingrui Xie

PUC Post-Hearing 4-3, page 2

xvi. Transmission Uncollectible Factor
xvii. Base Transition Charge
xviii. Transition Charge Adjustment
xix. Net Metering Charge
xx. LTC Recovery Factor
xxi. LTC Recovery Reconciliation Factor
xxii. Energy Efficiency Program Charge
xxiii. Renewable Energy Standard Charge
xxiv. Performance Incentive Factor

Prepared by or under the supervision of: Jingrui Xie

PUC Post-Hearing 4-4

Request:

For what purposes does the Company use its peak load forecast?

Response:

The Company uses its peak load forecast for system reliability procurement ("SRP"), the Rhode Island System Data Portal, and capacity reviews and area studies in connection with Electric Infrastructure, Safety, and Reliability ("ISR") planning.

System Reliability Procurement

Forecasting peak electric load is necessary for the Company's capital planning process so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.[1] NWA opportunities are then identified with this information in hand from system planning and as part of the distribution planning process.

The results of the peak electric load forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used. The 50/50, or weather-normal scenario is used for capacity market, strategic scenarios, incentive mechanisms and other relevant work.[2]

Rhode Island System Data Portal

Peak electric load forecasts are used in the development and analyses of the Rhode Island System Data Portal ("Portal"). Specifically, the forecasts are used to develop the feeder analyses for the Heat Map tab of the Portal, with the Distribution Assets Overview and Sea Level Rise tabs mirroring the Heat Map tab data. The annual Electric Peak (MW) Forecast reports are also uploaded to the Portal for public reference.

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[1] See Bates 91, http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf
[2] See Bates 93, http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

Electric Infrastructure, Safety, and Reliability - Capacity Reviews and Area Studies

Before developing the annual ISR Plan, the Company conducts an annual load forecast and routine system analyses on its distribution system in the form of capacity reviews, area studies, also known as area planning studies, and other integrated planning analyses. Capacity reviews are completed annually using the most recent load forecast for each of the study areas in the Company's service territory. A capacity review is conducted to identify thermal capacity constraints and assess the capability of the network to respond to contingencies that might occur. In preparing for the FY 2023 Electric ISR Plan, the Company completed 100% of the annual capacity reviews for FY 2023 using the FY 2022 electric forecast. The capacity reviews inform the execution of the Company's long-range system capacity studies which are performed through a series of area planning studies. Area planning studies are comprehensive technical reviews of areas within the Company's service territory to determine system needs and solutions over a 10-15 year timeframe.[3]

Actual feeder peak load values from the prior year, along with forecast information described above, are the basis for the capacity reviews performed by Distribution Planning & Asset Management. Capacity reviews are completed annually. They identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies.[4]

[3] See FY 2023 Electric ISR Plan, Bates 27, http://www.ripuc.ri.gov/eventsactions/docket/5209-NGrid-Book1-Electric%20ISR%20FY2023%20Plan%20(PUC%2012-20-21).bates.pdf
[4] See FY 2023 Electric ISR Plan, Bates 32, http://www.ripuc.ri.gov/eventsactions/docket/5209-NGrid-Book1-Electric%20ISR%20FY2023%20Plan%20(PUC%2012-20-21).bates.pdf

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PUC Post-Hearing 4-5

Request:

Please clarify whether the Company's peak load forecast counts non-persistent demand savings from any EE program or measure other than Home Energy Reports. Specifically address the ConnectedSolutions programs in your response.

Response:

The Company's peak load forecast released in Fall 2021 only accumulates persistent EE program savings. Demand savings from Home Energy Reports are the only non-persistent savings.
The Connected Solution programs is a demand response program. The Company does not accumulate impacts from Demand Response programs, including Connected Solutions, across years.

Prepared by or under the supervision of: Jingrui Xie

PUC Post-Hearing 4-6

Request:

For any given year, how does the Company's Energy Efficiency team develop the energy and demand savings numbers that it reports to the Load Forecasting Team? Please describe what information the energy efficiency team provides to the forecasting team.

Response:

Each year, the Company's Energy Efficiency team provides the most current planned energy and peak savings for the upcoming year. They also provide actual energy and demand savings reductions achieved from the prior year's programs.

The energy and demand savings are also broken down at the program level, which allows for the reporting of the Home Energy Report program's non-persistent energy and demand savings and the persistent energy and demand savings of other programs. This allows for the categorization of persistent and non-persistent energy and demand savings as presented in Table 1 in the response to PUC 2-5 for the purpose of the electric load forecast.

Prepared by or under the supervision of: Jingrui Xie

PUC Post-Hearing 4-7

Request:

Provide 2 tables formatted similarly to the tables filed in response to PUC 2-5 that show the Energy Efficiency Assumptions for the peak load forecasts dating back to 2013, distinguishing between the pre-2021 forecasting methodology and the post-2021 forecasting methodology.

Response:

In Attachment PUC 4-7, Table 1 shows the energy efficiency (EE) demand savings assumptions for the Company's 2021 peak load forecast (i.e., the current methodology), and Table 2 shows the EE demand savings assumptions if the old (i.e., prior to 2021) method was used.

In Table 1:

- Column (a) shows the historic and forecasted annual incremental demand savings from Home Energy Reports, which are non-persistent demand savings that started in 2013.
- Column (b) shows the historic and forecasted annual incremental persistent demand savings.
- Column (c) shows the accumulation of persistent demand savings over time.
- Column (d) shows the total demand savings in each year, which includes the accumulated persistent demand savings and each year's claimable non-persistent demand savings.

In Table 2:

- Column (e) shows the historic and forecasted annual incremental demand savings. The sum of column (a) and (b) of Table 1 equals to the value in column (e) of Table 2 for each year being presented.
- Column (f) shows the historic and forecasted cumulative demand savings, which accumulated the non-persistent savings.

Prepared by or under the supervision of: Jingrui Xie

	Table 1: Energy Efficiency Assumptions for Electric Peak Load Forecast (2021 Method)							Table 2: Energy Efficiency Assumptions for Electric Peak Load Forecast (pre-2021 Method)			
	Calendar Year	**State**	**Behavorial Savings (Home Energy Report)**	**Persistent Savings**	**Persistent Savings**	**Total Savings**		**Calendar Year**	**State**	**Savings**	**Cumulative Savings**
			Incremental MW	*Incremental MW*	*Cumulative MW*	*Cumulative MW*				*Incremental MW*	*Cumulative MW*
			(a)	*(b)*	*(c)*	*(d)*				*(e)*	*(f)*
(1)	2013	Actuals	1	26	147	148		2013	Actuals	*27*	147
(2)	2014	Actuals	4	34	181	185		2014	Actuals	*39*	185
(3)	2015	Actuals	4	29	210	214		2015	Actuals	*33*	219
(4)	2016	Actuals	4	27	237	241		2016	Actuals	*31*	249
(5)	2017	Actuals	4	26	263	267		2017	Actuals	*29*	279
(6)	2018	Actuals	3	26	289	292		2018	Actuals	*29*	307
(7)	2019	Actuals	3	27	315	318		2019	Actuals	*30*	337
(8)	2020	Actuals	3	20	336	339		2020	Actuals	24	360
(9)	2021	Forecasts	3	22	357	361		2021	Forecasts	25	386
(10)	2022	Forecasts	3	16	373	376		2022	Forecasts	19	404
(11)	2023	Forecasts	3	18	391	394		2023	Forecasts	21	425

PUC Post-Hearing 4-8

Request:

Update Tables 1 and 2 from PUC 2-5 to accurately reflect the persistence of energy savings from the Energy Efficiency program dating back to 2013 using actual measure lives (i.e. accumulating persistent savings from any given year based on their precise measure lives).

Response:

The Company does not reduce the historical or forecasted energy efficiency savings impacts for the varying EE measure and program useful lives (except for the behavioral type programs discussed in PUC 2-5). For these non-behavioral EE programs, the assumption is that all measures are replaced in-kind and/or with more efficient items when they reach the end of their useful lives.

For example, if an efficient refrigerator was installed and credited to the EE program X years ago and now reaches the end of its useful life, it is assumed that the new refrigerator will be at least as efficient, if not more, than the one being replaced. Thus, for forecasting the assumption is that loads will not increase as measures reach their end of life and therefore it is appropriate to not raise loads for this.

The Company does take measure lives into account for the calculation of lifetime energy savings in its energy efficiency programs. It is appropriate for the Company to claim credit for net lifetime energy savings from measures installed in a given year because the cumulative savings of a measure over its lifetime it is tied to the spending of SBC funds in a given year.

PUC Post-Hearing 4-9

Request:

Update the Company's response to PUC 1-12 to reflect the correct reconstituted load impact for the period of April 2022 – March 2023. In your response, include a detailed explanation of how the Company calculated the reconstituted load impact.

Response:

Please see Attachment PUC 4-9 for the updated data in the period of April 2022 - March 2023. Page 2 of the attachment is the same data and adds the date and time of the monthly peak.

The reconstituted load is based on taking the actual generation of each net metered and REG project that is over 25 kW at the time of the monthly peak (qualifying facilities and DG Standard Contract projects are already in the load calculations) and adding it to the underlying loads. As the time of the monthly peak varies by month, the amount of generation that is added changes based on the operation all the underlying generators. As an example, solar projects peak in the early afternoon, whereas wind projects peak later in the evening or overnight. If the peak hour is at a time with minimal or no generation (see October values which had a monthly peak at 6 pm), the reconstituted amount was zero kW, whereas in the summer month with a peak at 5 pm or 6 pm, solar is still generating at that time so will contribute to the monthly peak loads. In the Company's prior discussion on this topic with some members of PUC staff in late 2020, the values were lower at that time simply due to the fact that there was approximately 150+ MWs of new net metered and REG projects interconnected since that time.

The Narragansett Electric Company
Estimated Changes in PTF Demand Charges
Estimated for the Year 2022 Due to Reconstitution of Regional Network Load

Line #	Period	(1) Annual RNS Rate ($/kW-Yr)	(2) Monthly PTF kW Load	(3) PTF Demand Charge	(4) Reconstituted Load Impact	(5) Revised Monthly PTF kW Load	(6) Revised PTF Demand Charge	(7) Variance PTF Demand Charge
1	April	$ 142.78	846,825	10,075,752	42,726	889,551	10,584,117	508,365
2	May	$ 142.78	1,028,841	12,241,427	29,090	1,057,931	12,587,548	346,121
3	June	$ 142.78	1,617,488	19,245,307	69,535	1,687,023	20,072,653	827,346
4	July	$ 142.78	1,543,633	18,366,561	49,618	1,593,251	18,956,929	590,368
5	August	$ 142.78	1,564,102	18,610,106	67,463	1,631,565	19,412,799	802,693
6	September	$ 142.78	1,232,500	14,664,616	42,516	1,275,016	15,170,483	505,867
7	October	$ 142.78	973,371	11,581,430	-	973,371	11,581,430	-
8	November	$ 142.78	1,168,768	13,906,316	15,267	1,184,035	14,087,967	181,651
9	December	$ 142.78	1,158,086	13,779,219	2,432	1,160,518	13,808,155	28,937
10	January	$ 147.09	1,091,298	13,376,585	28,606	1,119,904	13,727,223	350,638
11	February	$ 147.09	1,008,998	12,367,793	39,026	1,048,024	12,846,154	478,361
12	March	$ 147.09	1,030,295	12,628,841	25,511	1,055,806	12,941,542	312,701
13	**Total**		**14,264,205**	**$170,843,952**	**411,790**	**14,675,995**	**$175,777,000**	**$4,933,048**

Notes
Line 1-9: Column (1) = Schedule AS-4 Line 1
Line 10-12: Column (1) = Schedule AS-4 Line 8
Line 1-12: Column (2) = ISO-NE Monthly Regional Network Load Reports January 2021 to December 2021 as per Schedule AS-3
Line 1-12: Column (3) = Column (1) x Column (2) / 12
Line 1-12: Column (4) = Internal Records
Line 1-12: Column (5) = Column (2) + Column (4)
Line 1-12: Column (6) = Column (1) x Column (5) / 12
Line 1-12: Column (7) = Column (6) - Column (3)

The Narragansett Electric Company
Estimated Changes in PTF Demand Charges
Estimated for the Year 2022 Due to Reconstitution of Regional Network Load

Line #	Period		(1) Annual RNS Rate ($/kW-Yr)	(2) Peak Date	(3) Peak Hour	(4) Monthly PTF kW Load	(5) PTF Demand Charge	(6) Reconstituted Load Impact	(7) Reconstituted Peak Date	(8) Reconstituted Peak Hour	(9) Revised Monthly PTF kW Load	(10) Revised PTF Demand Charge	(11) Variance PTF Demand Charge
1	April	$	142.78	4/16/2021	12:00	846,825	10,075,752	42,726	4/16/2021	12:00	889,551	10,584,117	508,365
2	May	$	142.78	5/26/2021	19:00	1,028,841	12,241,427	29,090	5/26/2021	19:00	1,057,931	12,587,548	346,121
3	June	$	142.78	6/29/2021	18:00	1,617,488	19,245,307	69,535	6/29/2021	18:00	1,687,023	20,072,653	827,346
4	July	$	142.78	7/16/2021	18:00	1,543,633	18,366,561	49,618	7/16/2021	18:00	1,593,251	18,956,929	590,368
5	August	$	142.78	8/12/2021	18:00	1,564,102	18,610,106	67,463	8/12/2021	18:00	1,631,565	19,412,799	802,693
6	September	$	142.78	9/15/2021	18:00	1,232,500	14,664,616	42,516	9/15/2021	18:00	1,275,016	15,170,483	505,867
7	October	$	142.78	10/14/2021	19:00	973,371	11,581,430	-	10/14/2021	19:00	973,371	11,581,430	-
8	November	$	142.78	11/23/2021	18:00	1,168,768	13,906,316	15,267	11/23/2021	18:00	1,184,035	14,087,967	181,651
9	December	$	142.78	12/8/2021	18:00	1,158,086	13,779,219	2,432	12/8/2021	18:00	1,160,518	13,808,155	28,937
10	January	$	147.09	1/29/2021	18:00	1,091,298	13,376,585	28,606	1/29/2021	18:00	1,119,904	13,727,223	350,638
11	February	$	147.09	2/1/2021	18:00	1,008,998	12,367,793	39,026	2/1/2021	18:00	1,048,024	12,846,154	478,361
12	March	$	147.09	3/2/2021	19:00	1,030,295	12,628,841	25,511	3/2/2021	19:00	1,055,806	12,941,542	312,701
13	**Total**					**14,264,205**	**$170,843,952**	**411,790**			**14,675,995**	**$175,777,000**	**$4,933,048**

Notes
Line 1-9: Column (1) = Schedule AS-4 Line 1
Line 10-12: Column (1) = Schedule AS-4 Line 8
Line 1-12: Column (2) = RNS Original Monthly Peak Date
Line 1-12: Column (3) = RNS Original Monthly Peak Hour
Line 1-12: Column (4) = ISO-NE Monthly Regional Network Load Reports January 2021 to December 2021 as per Schedule AS-3
Line 1-12: Column (5) = Column (1) x Column (3) / 12
Line 1-12: Column (6) = Internal Records
Column (7) = RNS Reconstituted Monthly Peak Date
Line 1-12: Column (8) = RNS Reconstituted Monthly Peak Hour
Line 1-12: Column (9) = Column (4) + Column (6)
Line 1-12: Column (10) = Column (1) x Column (9) / 12
Line 1-12: Column (11) = Column (10) - Column (5)

PUC Post-Hearing 4-10

Request:

For the purposes of LNS cost allocation, confirm whether or not the Company will adjust its non-PTF demand for the period of April 2022 – March 2023 for the reconstituted load impact from 4-9.

Response:

Yes. The Company will adjust its Non-PTF demand due to the new RNL reconstitution requirements.

PUC Post-Hearing 4-11

Request:

Using the reconstituted load impact from 4-9, re-calculate the non-PTF demand charge for the period of April 2022 – March 2023.

Response:

Please see Attachment PUC 4-11 for the Non-PTF reconstituted load impact in the period April 2022 - March 2023. Page 2 of the attachment shows the same information as page 1 and adds the date and time of each monthly peak.

The Narragansett Electric Company
Estimated Changes in Non-PTF Demand Charges
Estimated for the Year 2022 Due to Reconstitution of Local Network Load

Line #	Period	(1) Annual LNS Rate ($/kW-Yr)	(2) Monthly Non-PTF kW Load	(3) Non-PTF Demand Charge	(4) Reconstituted Load Impact	(5) Revised Monthly Non-PTF kW Load	(6) Revised Non-PTF Demand Charge	(7) Variance Non-PTF Demand Charge
1	April	$ 3.01	845,673	2,541,661	42,726	888,399	2,670,074	128,413
2	May	$ 3.01	1,028,841	3,092,172	29,090	1,057,931	3,179,601	87,430
3	June	$ 3.01	1,617,488	4,861,345	69,535	1,687,023	5,070,332	208,987
4	July	$ 3.01	1,543,633	4,639,375	49,618	1,593,251	4,788,501	149,126
5	August	$ 3.01	1,564,102	4,700,893	67,463	1,631,565	4,903,652	202,759
6	September	$ 3.01	1,232,500	3,704,267	42,516	1,275,016	3,832,049	127,781
7	October	$ 3.01	973,371	2,925,457	-	973,371	2,925,457	-
8	November	$ 3.01	889,428	2,673,166	15,267	904,695	2,719,051	45,885
9	December	$ 3.01	1,084,625	3,259,831	48,844	1,133,469	3,406,631	146,800
10	January	$ 3.15	1,080,998	3,403,382	28,606	1,109,604	3,493,445	90,062
11	February	$ 3.15	1,003,972	3,160,875	39,026	1,042,998	3,283,743	122,868
12	March	$ 3.15	1,021,292	3,215,404	25,511	1,046,803	3,295,722	80,318
13	**Total**		**13,885,923**	**$42,177,829**	**458,202**	**14,344,125**	**$43,568,259**	**$1,390,430**

Notes
Line 1-9: Column (1) = Schedule AS-7 Page 1 Line 12
Line 10-12: Column (1) = Schedule AS-7 Page 2 Line 8
Line 1-12: Column (2) = Monthly Network Load Files for December 2020- November 2021 as per Schedule AS-6 Column (1)
Line 1-12: Column (3) = Column (1) x Column (2)
Line 1-12: Column (4) = Internal Records
Line 1-12: Column (5) = Column (2) + Column (4)
Line 1-12: Column (6) = Column (1) x Column (5)
Line 1-12: Column (7) = Column (6) - Column (3)

The Narragansett Electric Company
Estimated Changes in Non-PTF Demand Charges
Estimated for the Year 2022 Due to Reconstitution of Local Network Load

Line #	Period	(1) Annual LNS Rate ($/kW-Yr)	(2) Peak Date	(3) Peak Hour	(4) Monthly Non-PTF kW Load	(5) Non-PTF Demand Charge	(6) Reconstituted Load Impact	(7) Reconstituted Peak Date	(8) Reconstituted Peak Hour	(9) Revised Monthly Non-PTF kW Load	(10) Revised Non-PTF Demand Charge	(11) Variance Non-PTF Demand Charge
1	April	$ 3.01	4/16/2021	12:00	845,673	2,541,661	42,726	4/16/2021	12:00	888,399	2,670,074	128,413
2	May	$ 3.01	5/26/2021	19:00	1,028,841	3,092,172	29,090	5/26/2021	19:00	1,057,931	3,179,601	87,430
3	June	$ 3.01	6/29/2021	18:00	1,617,488	4,861,345	69,535	6/29/2021	18:00	1,687,023	5,070,332	208,987
4	July	$ 3.01	7/16/2021	18:00	1,543,633	4,639,375	49,618	7/16/2021	18:00	1,593,251	4,788,501	149,126
5	August	$ 3.01	8/12/2021	18:00	1,564,102	4,700,893	67,463	8/12/2021	18:00	1,631,565	4,903,652	202,759
6	September	$ 3.01	9/15/2021	18:00	1,232,500	3,704,267	42,516	9/15/2021	18:00	1,275,016	3,832,049	127,781
7	October	$ 3.01	10/14/2021	19:00	973,371	2,925,457	-	10/14/2021	19:00	973,371	2,925,457	-
8	November	$ 3.01	11/23/2021	18:00	889,428	2,673,166	15,267	11/23/2021	18:00	904,695	2,719,051	45,885
9	December	$ 3.01	12/17/2020	18:00	1,084,625	3,259,831	48,844	12/17/2020	18:00	1,133,469	3,406,631	146,800
10	January	$ 3.15	1/29/2021	18:00	1,080,998	3,403,382	28,606	1/29/2021	18:00	1,109,604	3,493,445	90,062
11	February	$ 3.15	2/1/2021	18:00	1,003,972	3,160,875	39,026	2/1/2021	18:00	1,042,998	3,283,743	122,868
12	March	$ 3.15	3/2/2021	19:00	1,021,292	3,215,404	25,511	3/2/2021	19:00	1,046,803	3,295,722	80,318
13	**Total**				**13,885,923**	**$42,177,829**	**458,202**			**14,344,125**	**$43,568,259**	**$1,390,430**

Notes
Line 1-9: Column (1) = Schedule AS-7 Page 1 Line 12
Line 10-12: Column (1) = Schedule AS-7 Page 2 Line 8
Line 1-12: Column (2) = LNS Original Monthly Peak Date
Line 1-12: Column (3) = LNS Original Monthly Peak Hour
Line 1-12: Column (4) = Monthly Network Load Files for December 2020- November 2021 as per Schedule AS-6 Column (1)
Line 1-12: Column (5) = Column (1) x Column (4)
Line 1-12: Column (6) = Internal Records
Line 1-12: Column (7) = LNS Reconstituted Monthly Peak Date
Line 1-12: Column (8) = LNS Reconstituted Monthly Peak Hour
Line 1-12: Column (9) = Column (4) + Column (6)
Line 1-12: Column (10) = Column (1) x Column (9)
Line 1-12: Column (11) = Column (10) - Column (5)

PUC Post-Hearing 4-12

Request:

Update Schedule NECO-11 using the revised forecasts of PTF and non-PTF demand charges from in the Company's responses to 4-9 and 4-11.

Response:

Based on the Company's response to PUC 4-9 and PUC 4-11, please see Attachment PUC 4-12 for an update to Schedule NECO-11 using the revised forecasts of PTF and non-PTF demand charges. The Company has calculated an illustrative estimated transmission expense of $238,924,010, as shown on Line (1) of Attachment PUC 4-12, that represents an increase of $6,388,815 in transmission expenses when compared to Schedule NECO-11.

The incremental impact of the changes described above on a residential Last Resort Service customer with monthly usage of 500 kWh is an increase of $0.49, or 0.4%.

Prepared by or under the supervision of: Daniel Gallagher

The Narragansett Electric Company
Calculation of Illustrative 2022 Base Transmission Factors
Effective April 1, 2022 through March 31, 2023

		Total	A16/ A60	C06	G02	B32/G32/X01	SL
(1)	Illustrative Estimated Transmission Expenses	$238,924,010					
(2)	Coincident Peak Allocator	100.00%	46.83%	10.26%	16.15%	26.44%	0.32%
(3)	Illustrative Estimated 2022 Transmission Expenses by Rate Class	$238,924,010	$111,883,909	$24,508,680	$38,597,358	$63,176,497	$757,566
(4)	Allocated Estimated 2021 Transmission Expenses	$222,081,877	$103,511,859	$22,955,601	$35,474,212	$59,268,978	$871,227
(5)	Increase/(Decrease) from Prior Year	$16,842,133	$8,372,050	$1,553,079	$3,123,146	$3,907,519	($113,661)
(6)	Percentage Increase/(Decrease) from Prior Year	7.58%	8.09%	6.77%	8.80%	6.59%	-13.05%
(7)	Forecast kW 2022	10,556,451			4,459,835	6,096,616	
(8)	Forecast kWh for the period April 1, 2022 through March 31, 2023	7,368,760,169	3,174,470,936	692,263,609	1,223,987,397	2,236,697,757	41,340,470
(9)	Current Transmission kW Charge				$4.57	$4.76	
(10)	Illustrative Transmission kW Charge				$4.97	$5.07	
(11)	Illustrative Transmission Expenses to be Recovered on a kW Basis	$53,075,223			$22,165,380	$30,909,843	
(12)	Illustrative Transmission Expenses to be Recovered on a kWh Basis	$185,848,787	$111,883,909	$24,508,680	$16,431,978	$32,266,654	$757,566
(13)	Illustrative Transmission kWh Charge		$0.03524	$0.03540	$0.01342	$0.01442	$0.01832

(1) Calculated per the revised forecasts of PTF and non-PTF demand charges from the Company's responses to PUC 4-9 and PUC 4-11 in this docket.
(2) Page 2, Column (m)
(3) Line (2) x Line (1)
(4) R.I.P.U.C. Docket No. 5127, Schedule NG-11, Page 1, Line (3)
(5) Line (3) - Line (4)
(6) Line (5) ÷ Line (4)
(7) per Company forecast
(8) per Company forecast
(9) per Summary of Retail Delivery Rates, R.I.P.U.C. 2095, effective 2/1/22
(10) Higher of current charge or Line (9) x (1 + Line (6)), truncated to 2 decimal places
(11) Line (7) x Line (10)
(12) Line (3) - Line (11)
(13) Line (12) ÷ Line (8), truncated to 5 decimal places

The Narragansett Electric Company
Calculation of Coincident Peak Allocator

		12 Months Ended 12/31/2008			12 Months Ended 12/31/2011			12 Months Ended 6/30/2017		
		Weight=		*33.3%*	*Weight=*		*33.3%*	*Weight=*		*33.4%*
	Rate Class	**kWh**	**Class 12CP**	**Load Factor at 12CP**	**kWh**	**Class 12CP**	**Load Factor at 12CP**	**kWh**	**Class 12CP**	**Load Factor at 12CP**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	A16-A60	3,016,600,197	554,463	62.1%	3,126,239,108	567,927	62.8%	3,066,425,000	549,214	63.7%
(2)	C-06	544,439,144	101,466	61.3%	565,451,276	101,174	63.8%	602,260,000	109,503	62.8%
(3)	G02	1,384,485,125	225,130	70.2%	1,332,784,896	213,873	71.1%	1,300,006,000	213,375	69.6%
(4)	B32-G32-X-01	2,713,533,938	389,839	79.5%	2,630,819,512	372,686	80.6%	2,428,386,000	367,614	75.4%
(5)	SL	70,565,193	5,590	144.1%	69,859,535	6,611	120.6%	43,695,000	5,078	98.2%
(6)										
(7)	System	7,729,623,597	1,276,488	69.1%	7,725,154,327	1,262,270	69.9%	7,440,772,000	1,244,784	68.2%

		Estimated - 12 Months Ended 03/31/2023			
		Average Load Factor at 12CP	**Forecasted kWh**	**Class 12CP**	**Estimated - 12 Months Ended 03/31/2023**
		(j)	(k)	(l)	(m)
(1)	A16-A60	62.9%	3,174,470,936	576,172	46.8%
(2)	C-06	62.6%	692,263,609	126,213	10.3%
(3)	G02	70.3%	1,223,987,397	198,766	16.2%
(4)	B32-G32-X-01	78.5%	2,236,697,757	325,342	26.4%
(5)	SL	121.0%	41,340,470	3,901	0.3%
(6)					
(7)			7,368,760,169	1,230,395	100.0%

(a) Company records
(b) 2008 average monthly CP
(c) Column (a) ÷ [Column (b) x 8,760 hours]
(d) Company records
(e) 2011 average monthly CP
(f) Column (d) ÷ [Column (e) x 8,760 hours]
(g) Company records
(h) 12 Months ended 6/17 average monthly CP
(i) Column (g) ÷ [Column (h) x 8,760 hours]
(j) Column (c) x 33.3% + Column (f) x 33.3% + Column (i) x 33.4%
(k) per Company forecast
(l) Column (k) ÷ Column (j) ÷ 8,760 hours
(m) Column (l) ÷ Column (l) Total

PUC Post-Hearing 4-13

Request:

How confident is the Company in its updated reconstituted load impact estimate from 4-9? As part of your response, describe the potential scenarios that could cause the actual reconstituted load impact to vary from the estimate.

Response:

As the estimate is based on actual hourly data for all DG, the Company is confident the estimated values will materialize. The impact is directly related to how much DG is actually operating at the time of the ISO-NE system peak (coincident with the ISO-NE system peak). Significant new land-based wind could cause actual costs to increase as wind is more likely to be generating at or close to its nameplate rating (installed size in MWs) during the time of monthly peaks, especially in the winter months, versus solar projects which typically generate much less than their nameplate rating at the times of non-winter months' peaks.

Prepared by or under the supervision of: Timothy Roughan

PUC Post-Hearing 4-14

Request:

If any new DG facilities greater than 25 kW interconnect to the Company's distribution system between April 2022 and March 2023, what impact might those facilities have on the reconstituted load impact estimate from 4-9?

Response:

Any DG that is operating during the time of a monthly peak will contribute to an increase in reconstituted loads. Therefore, as more DG is installed, the reconstituted loads will increase.