Andrew S. Marcaccio
Senior Counsel

February 23, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5209 - Proposed FY 2023 Electric Infrastructure, Safety, and Reliability Plan
Responses to Data Requests – PUC Set 2

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 responses to the Public Utilities Commission's Second Set of Data Requests in the above-reference matter.[1]

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263.

Sincerely,

Andrew S. Marcaccio

Enclosure

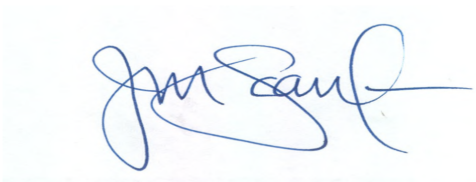
cc: Docket 5209 Service List
Jon Hagopian, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division

[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.



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Joanne M. Scanlon

February 23, 2022
Date

Docket No. 5209 - National Grid's Electric ISR Plan FY 2023
Service List as of 01/10/2022

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PUC 2-1
Forecasting

Request:

National Grid describes the need to conduct summer and winter peak load forecasting beginning on Bates 30. Given the forecasted increase in distributed generation, for example in National Grid's 2022 Electric Peak Forecast, is there a planning need that requires a consideration of a minimum load forecast in the shoulder months?

Response:

There is a planning need to consider minimum loads, particularly for distributed generation interconnection studies. This planning need could lead to minimum load forecasts, and the Company is exploring such concepts. However, a forecasted minimum load would not be necessary until integrated planning ideas are further developed and proactive infrastructure investment is allowed to be recovered prior to specific distributed generation applications and is part of a coordinated state-wide effort for proactive investments.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-2
Forecasting

Request:

Does National Grid perform any forecasts that represent scenarios consistent with the emissions reductions requirements of the Act on Climate?

Response:

The forecasts being referred in this filing was conducted in Fall 2020 and before the Act on Climate was signed by the governor in April 2021. The Act on Climate was not referred to in this specific Fall 2020 forecast.
The Act on Climate sets the emission reduction goals as well as requires the Executive Climate Change Coordinating Council (EC4) to deliver an update to the 2016 Greenhouse Gas Emissions Reduction Plan by the end of 2022 and a plan to incrementally reduce climate emissions to net-zero by 2050 by 2025[1]. When the Company developed its latest forecasts in Fall 2021, these plans were still under development. However, the Company leveraged existing policies, updated market studies, and regional operator and State agencies' outlook in developing its Distributed Energy Resources (DERs) forecasts in Fall 2021. These updated DER forecasts reflect a significant increase in the Company's expectations on DER technology's penetrations compared to its Fall 2020 forecasts. Also, the Company's Fall 2021 forecasts on some DER technologies are already beyond the level being supported by State's existing policies. In details:

- For the transportation electrification sector, the Company significantly increased its expectations on electric vehicle adoptions compared to its 2020 forecast. The Company updated its light-duty electric vehicle adoption projection based on Bloomberg's 2021 Long-term Electric Vehicle Outlook (BNEF-2021). The BNEF-2021considers technologies, policies, and market status in its study and it is an well-known study in the industry. It reflects an expectation on zero-emission vehicles sales to reach 31% of the total light-duty vehicle sales by 2030 and 59% by 2035, while it was only 2% - 3% at the State when the Company developed its Fall 2021 forecast. The Company also incorporated estimated impacts from medium- and heavy-duty electric vehicles and electric buses into its forecasting process. The expectations on medium- and heavy-duty electric vehicles and electric buses are based on BNEF-2021 and the ZEV MOU.
- For the building electrification sector, the Company followed the projection developed by ISO-NE for the State of Rhode Island [2]. About 12% of home is expected to be electrified by 2030 and this number will grow to 23% by the year 2036.

[1] http://climatechange.ri.gov/aoc/; State of Rhode Island Climate Change, as of February 16, 2022
[2] https://www.iso-ne.com/static-assets/documents/2021/02/lfc2021_final_heating_elec.pdf; ISO-NE, February 19, 2021

- For the renewable energy generation sector – specifically distribution-level solar PV, the Company has achieved its record-level connection in 2019 and the Company assumes the solar PV connection will remain at this record-level for the near future. This level of connection is way above the estimated annual connection supported by the State's existing Renewable Energy Growth Program (REGP) as estimated by ISO-NE in its 2021 forecast[3] and 2022 drafted forecast [4].

- For the energy efficiency sector, the Company leveraged the numbers from its energy efficiency filings.

The Company will keep monitoring the ongoing efforts by the State's agency in developing the pathway and action plans to achieve the Act on Climate emission reduction goals and may develop corresponding scenarios once clear pathway and State DER targets are identified by the State agencies.

[3] https://www.iso-ne.com/static-assets/documents/2021/02/draft_2021_pv_forecast.pdf, ISO-NE, February 22, 2021
[4] https://www.iso-ne.com/static-assets/documents/2022/02/draft_2022_pv_forecast.pdf, ISO-NE, February 14, 2022

PUC 2-3
Forecasting

Request:

Referencing PUC 1-20, please explain how "beneficial electrification" is treated differently for load forecasting than other additions to forecasted load

Response:

For this forecast, beneficial electrification refers to electric vehicles, as discussed in response to Division 1-3 and PUC 1-20, electric vehicle (EV) charging load is added to the forecasted load. It follows the same overall process as with all of the other DERs as demonstrated in Chart 3 of the Company's bates (page 30), however where the other DERs such as energy efficiency and solar PV reduce loads, and electric vehicles add to load.

Prepared by or under the supervision of: Joseph Gredder and Jingrui Xie

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PUC 2-4
Forecasting

Request:

Referencing PUC 1-24, please confirm that the Company has only reviewed various levels of DER on the distribution system as a whole and not the "locational scenarios" of these various levels.

"To assess the scope and scale of potential distribution system needs over the ten-year horizon of the GMP, the Company developed multiple customer DER adoption scenarios with varying levels of renewable DG interconnection and BE adoption within the transportation and heating sectors. While a high customer DER adoption future is envisioned, there is uncertainty with respect to where and when the DER will be interconnected. Therefore, two primary customer DER adoption scenarios were developed to "bookend" a range of possible future outcomes:

1) a low DER adoption (Low DER) scenario based on historic (2018-2020) DER adoption rates with an annual reduction in renewable DG adoption over time, and
2) a higher DER adoption (High DER) scenario consistent with achieving Rhode Island's 2050 goal of 80% greenhouse gas emissions reductions compared to a 1990 baseline (80x50 goal)." (Docket No. 5114 at Bates 118).

Response:

The Company has reviewed locational aspects of the low DER and high DER scenarios. However, this locational analysis was the Company's first attempt at such an analysis, which was limited to a manual scatter approach across a subset of the Company's circuits to test DER penetration impacts on distribution circuit models. Small and large DER were varied locationally for the low DER and high DER cases and the results were scaled to system values. There are limitations to this approach, such as the analysis did not consider available property nor propensities of customer adoption. As a result, this is a preliminary, high-level approach to locational reviews and could be considered a novice level approach. . .

PUC 2-5

Customer Request

Request:

Regarding the data in Chart 14 on Bates 58

a. How are the budgets for the New Business categories developed, and
b. is there a number of buildings or some similar metric that the New Business Commercial and Residential categories related to? If so, please provide those.

Response:

a. The specific work performed in the New Business categories is generally not known in advance, so budgets are proposed based on historical costs using a Twelve Month Moving Annual Total (MAT), adjusted for known trends or one-time items. For specific New Business projects known in advance, typically Commercial projects, a budget is established. No such projects are included in the FY 2023 budget.

b. The Company has investigated incorporating the use of data, such as trending of existing customer requests for new or upgraded service, into budget planning. However, because these categories are driven by customer requests, there is inherent uncertainty about our ability to forecast future volume and size of new service requests. Therefore, the Company has opted to not use trending existing service requests in budget planning at this time.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-6
Customer Request

Request:

Referencing the Company's response to PUC 1-13.a, please confirm that if the actual cost of an Impact Study and System Modification exceeds the amount provided to a DG customer prior to the start of construction and the customer is not advised of such increased cost in writing, the customer is not charged the excess cost.

Response:

Impact Study Costs

With regard to charging customers for actual study costs that exceed the Company's initial study cost estimate, pursuant to Section 7 of Exhibit G of the Company's Standards for Connecting Distributed Generation ("Interconnection Tariff") (R.I.P.U.C. No. 2224), if the Customer executes an Interconnection Service Agreement ("ISA"), then a final accounting of the costs collected under the Customer's impact study agreement shall be performed in accordance with the terms of the ISA. If the Interconnecting Customer does not execute an ISA, the Company, within ninety (90) business days after completion of the study and all Company work orders have been closed, provides an Interconnecting Customer with a written final accounting report of any difference between (a) the Interconnecting Customer's cost responsibility under the impact study agreement, and (b) the Interconnecting Customer's previous aggregate payments to the Company for such study. Costs that are statutorily- based are not subject to final accounting or reconciliation under this provision (e.g., statutorily set study fees for the ISRDG), but may be reconciled at any time only if the costs exceed the statutory fee and the Company seeks to collect actual costs in accordance with the applicable statute. If the Interconnecting Customer is not advised of such a cost increase in writing, the Interconnecting Customer is not charged the excess cost. Please note for an Impact Study for Renewable DG ("ISRDG") study, the Company is collecting actuals up to its full amount from the Interconnecting Customer as mentioned above. The Company has adopted a practice to reconcile ISRDG study costs as soon as the study is completed.

System Modification Costs

With regard to charging customers for actual System Modification costs that exceed the Company's cost estimate provided with such customer's ISA, , Section 5.1 of Exhibit I of the Interconnection Tariff requires the Company to advise the Interconnecting Customer, in writing, in advance of any *expected* cost increase for work to be performed up to a total amount of increase of 10% only. Any such changes to the Company's costs for the work shall be subject to the

Interconnecting Customer's consent. In 2021, the Company implemented a process by which we compare estimates that were generated during the Impact Study process and estimates that are generated after detailed design of System Modifications is complete. This allows the Company to advise the Interconnecting Customer expected cost increases and collect an additional 10% of collected amount only If the Interconnecting Customer is not advised of an expected cost increase prior to construction in writing, the Interconnecting Customer is not charged the expected excess cost.

For actual System Modification costs that exceed the Company's ISA cost estimates, the Company follows Section 5.2 of Exhibit I of the Interconnection Tariff, which states, in pertinent part:

> The Company within ninety (90) business days after completion of the construction and installation of the System Modifications described in an attached exhibit to the Interconnection Service Agreement and all Company work orders have been closed, shall provide Interconnecting Customer with a final accounting report of any difference between the (a) Interconnecting Customer's cost responsibility under the Interconnection Service Agreement for the actual cost of such System Modifications and for any Impact or Detailed Study performed by the Company, and (b) Interconnecting Customer's previous aggregate payments to the Company for such System Modifications and studies. Costs that are statutorily-based shall not be subject to either a final accounting or reconciliation under this provision (e.g. statutorily set study fees for the ISRDG),but may be reconciled at any time only if the costs exceed the statutory fee, and the Company seeks to collect actual costs in accordance with the applicable statute.

If the Interconnecting Customer is not advised of such a cost increase in writing via a final accounting report, the Interconnecting Customer is not charged the excess cost.

PUC 2-7
Customer Request

Request:

Using the Final Accounting provided in Docket No. 5206, Attachment PUC 1-1-1, please provide a schedule showing how that project is recorded in rate base. Identify the plant in service amounts, the CIAC amounts, and explain what happens to any difference between plant in service and CIAC for that project.

Response:

Each work order associated with the project referenced in Final Accounting provided in Docket 5206 Attachment PUC 1-1-1 was reconciled separately. For this project, the Company performed an ISRDG study and collected statutory fees of $10,000 as the initial CIAC. The Company collected study overrun costs of $21,467.49 from the customer..

For System Modifications, the Company collected and deposited a CIAC as per initial estimates to its distribution line work order and its substation work order as shown in column C in the table below.. The amounts in the table below are total spending, capex, opex and removal. For distribution line work, the Company spent $52,169.55 less than the original estimate. For substation work, the Company spent $207,648.40 more than its original estimate. The net project spending was $155,478.85. At the end of reconciliation, the Company applied excess funds from the distribution line work order to the substation work order to reduce the overrun and did not charge the customer because the Company did not advise the Interconnecting Customer of overrun prior to start of the construction.

Work Order		Actual Spend (A)	CIAC/Customer Payments (B)	Invoiced after reconciliation (C)	Difference (D)
Study		$31,467.49	$10,000	$21,467.49	$0.00
Distribution Line		$640,732.85	$692,893.40	$0.00	($52,169.55)
Substation		$524,717.85	$317,069.45	$0.00	$207,648.40
Total		$1,165,441.70	$1,009,962.85	$0.00	$155,478.85

Prepared by or under the supervision of: Vishal Ahirrao and Timothy Roughan

PUC 2-8
Customer Request

Request:

In PUC 1-21, the Company explained how it has engaged to reduce a specific customer's infrastructure costs related to EVSEs. Please explain whether the Company has engaged with policy makers, public transit authority decision makers, or other larger users of transportation to discuss how/where electric vehicle charging infrastructure could be deployed in a manner that reduces system power costs or can otherwise provide benefits to the electric system. If so, please describe. If not, why not?

Response:

The Company has begun working with large users of transportation, who recently have shown growing interest in electric vehicles (EVs). As stated in PUC 1-21, the Company evaluates sites for large users to verify adequate system capacity to supply the customer's needs, while ensuring any charging infrastructure is deployed at the least cost possible.

Aside from the discussion during direct interconnection work, the Company does not discuss how/where electric vehicle charging infrastructure could be deployed in a manner that reduces system power costs. This is because electric vehicle charging stations, by nature, do not reduce system power costs, unless equipped with vehicle-to-grid technology or tied to other technologies such as battery storage.

The Company is supportive of these technologies and has a number of projects underway. In addition to the example provided in PUC 1-21, we are currently working with a large school bus transportation provider to plan chargers to support up to four electric school buses, as well as a municipality who will be installing V2G-capable fast chargers, which are able to discharge power from the bus batteries when not in use.

PUC 2-9
Damage/Failure

Request:

On Bates 59 of the Plan, National Grid explains that "the Company sets [the Damage/Failure] budget based on multi-year historical trends" with additional portions for carryover. Please provide the analysis of multi-year historical trends and any adjustments to the Plan year upon which the Damage/Failure budget was made. Please explain the approximately $2 million increase in the context of this analysis and adjustments.

Response:

The Damage/Failure category of spending is made up of costs to replace equipment that unexpectedly fails or becomes damaged from storms, vehicle accidents, vandalism, and other unplanned causes. The specific work performed is generally not known in advance, so the budget for blanket projects is proposed based on historical costs using a 12-month Moving Annual Total (MAT), adjusting for any known trends, expected changes or one-time items. This is consistent with practices in previous years. The table below shows the MAT balances for blanket projects as of June for the previous five years.

	Moving Annual Total
Jun-2017	11,874,799
Jun-2018	9,948,017
Jun-2019	9,526,225
Jun-2020	10,452,481
Jun-2021	10,336,919
FY 2022 Budget	9,528,000
FY 2023 Budget	10,620,000

Adjustments made to the MAT data include the addition of escalators for wages, benefits and materials increases and general inflation.

The approximately $2.0 million increase in Damage/Failure category relates to $1 million in increased costs shown in the MAT data and the forecasted remaining spending to replace the Westerly #2 Transformer.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-10

Damage/Failure

Request:

Why are reserves needed for this category? Please provide an analysis of the historical use of reserves in this category.

Response:

The Damage/Failure reserves are established in the budget as estimates for asset failures that may take place during the year and be accounted for in a specific project. The budget has been fairly consistent since FY 2015.

Please see the table below that summarizes the annual budgets and actual spending of Damage/Failure reserves, with FY 2022 being a forecasted amount.

$ in '000s	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY 2023
Budgeted Reserves	**$1,709**	**$1,475**	**$1,200**	**$1,000**	**$1,000**	**$1,100**	**$537**	**$885**	**$820**	**$900**	**$920**	**$950**
Transformer and related equipment failures	$0	$10	($3)	$1,645	$236	$2,088	$508	$1,190	$1,870	$0	$903	
Cable failures	847	3	0	0	0	0	0	0	138	(0)	0	
Riser/Foundation/Pole failures	0	0	0	0	0	0	0	225	31	23	600	
Breaker failures	0	0	0	334	14	179	3	0	0	0	0	
Other	832	93	818	134	410	225	13	4	69	0	0	
Actual/Forecasted Capital Spending	**$1,679**	**$106**	**$815**	**$2,113**	**$660**	**$2,493**	**$523**	**$1,419**	**$2,109**	**$23**	**$1,503**	

Prepared by or under the supervision of: Patricia Easterly

PUC 2-11
Damage/Failure

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, why does the forecasted budget include increases to Reserves for Damage/Failure?

Response:

The budgets for FY 2024 through FY 2027 for Reserves for Damage/Failure increase slightly each year to indicate probable cost increases associated with wages, benefits and materials and general inflation.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-12
Asset Condition

Request:

What conditions or characteristics make it reasonable to eliminate/convert the 11.5 kV and 4.16 kV assets related to the Admiral Street project but that don't exist in the Dyer Street project?

Response:

For each indoor substation in Providence, the Providence area study compared the cost of converting 4.16kV and 11.5kV feeders to 12.47kV to the cost of replacing the indoor substation in kind. Dyer Street substation was the only indoor substation that was determined to be more economical to rebuild at 4.16kV than to convert to 12.47kV. This is due to significant underground components through the most complex areas of Providence, including the Jewelry District (Innovation District), East Side, and downtown area. Conversions of these circuits would require a significant amount of time to complete and would require 12.47 kV capacity which is not currently available. Additionally, the asset condition issues were most severe at Dyer Street substation.

PUC 2-13
Asset Condition

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, for the three projects in Pre-Project Development (Centerdale Sub, Division Street Transformers, and Apponaug LT Plan):

a. Please provide a brief description of the projects' need and scope (e.g., what is being replaced and why). Please also briefly explain if the current project includes consideration of upgrades to system capacity and performance within the asset replacement plan.
b. What was/is the useful life of the existing assets?
c. Based on current development of the projects, what is the expected useful life of the potential new assets?
d. What forecast information (e.g., load, generation, etc.), if any, is used to determine how to engineer the new assets to serve customers over their useful (or book) lives, and how?
e. How would National Grid determine that Asset Condition projects like these should include a component of design to improve system capacity and performance?

Response:

a. Centredale Substation:

The exiting Centredale substation is a 23/12.47/4.16 KV Distribution Substation which consists of one 12.47 KV feeder and three 4.16 kV feeders. An inspection of the substation performed by subject matter experts identified numerous asset condition issues with the existing equipment including but not limited to clearance issues with the regulators, oil circuit breakers, VSA recloser, disconnects, control equipment, and the 23kV airbreak switches. In order to address the asset condition issues at the substation, it is recommended that the entire substation be replaced.

The recommended plan includes rebuilding the substation with two new modular 23/12.47kV transformers and feeder positions. The existing 4.16kV feeders will be converted to 12.47kV and the 4.16kV portion of the station will be eliminated. All existing assets will be removed and a new control house will be constructed.

The area study did not identify any system capacity issues within the study period; however, the new equipment will increase capacity at the substation by approximately 7.5MVA. This increase is a result of standard transformer sizes and the conversion of a 4.16kV system to a 12.47kV system. The details of this plan will be included in the Northwest Rhode Island area study report.

Division St substation:

The Division St substation consists of two 34.5-12.47kV transformers and four 12.47kV feeders. An inspection of the substation performed by subject matter experts identified asset condition issues with some of the existing substation equipment including the two 34.5-12.47kV transformers, the 3311-2T and 3312-1T 34.5kV motor operated air-break switches and station lighting arrestors. Additionally, there are several live parts requiring bushing covers and there is no existing electrical animal fence.

The recommended plan includes replacement of both 34.5kV-12.47kV transformers, the 3311-2T and 3312-1T 34.5kV air-breaks and all lighting arrestors in addition to the installation of animal protection.

The area study did not identify any system capacity issues within the study period; however, there is an operations scheme that is disabled due to the size of the existing transformers which is addressed by the recommended plan. The new transformers will increase capacity at the substation by approximately 40MVA. This is a result of standard transformer sizes. The details of this plan will be included in the Central Rhode Island West area study report.

Apponaug Substation:

The Apponaug short term and long term plans were both identified in the completed Central Rhode Island East area study. The completed Apponaug short term plan included removal of the double bus 23 kV switchyard and installation of relayed reclosers for protection of the No 3 and No 4 transformers. The Apponaug long term plan will address all remaining asset condition concerns and algins with work performed in the short term project.

After the short term plan was carried out, another inspection of the substation was performed by subject matter experts identified asset condition issues with some of the existing substation equipment including but not limited to the 23kV 4T Voltage Transformer, wooden 23kV air-break structures, 12.47kV 3F1 Vacuum Circuit Recloser, the two 23-12.47kV transformers, lack of EMS monitoring, voltage regulators, control building, 321BT gang operated load break switch, and numerous foundation issues.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

In order to address all of these asset condition concerns, it is recommended to rebuild the substation with two 23-12.47kV modular transformers and feeders. All existing equipment will be removed with the exception of the control house which will be refurbished.

The area study did not identify any system capacity issues within the study period so this project will not increase capacity at the substation. This project is included in the Central Rhode Island East Area study.

b. Generally, the assets identified for replacement in the projects described above exceed the normal expected useful life for company assets described in part c below. For example, the Centredale transformers vary to 50-70 years old and the Centerdale breakers vary from 40-70 years old. Additionally, the Division St transformers and motor operated air-breaks are approximately 50 years old. Lastly, the Apponaug transformers and 23kV motor operated air-break switches are approximately 50 years old.

c. The Company generally plans for a 20 to 40 year expected useful life for its assets. Electronic assets such as relays and batteries can have a 20-year useful life. Electric assets, such as breakers and regulators, typically have a 30-year useful life. Transformers and mechanical and structural assets typically have a 40-year useful life.

d. Area studies are performed across a 10-15 year study horizon and use the latest Electric Peak Forecast Report from the year the study is performed. Area studies recommendations provide a comprehensive solution to address all system performance concerns in the study area through the end of the study period. Though the useful life of the asset spans past the end of the area study horizon and the current forecast, the Company considers any possible future needs in the design of its recommendations. For example, the Company will design a new substation with the ultimate future build out in mind so if additional load growth occurs in the future, the existing assets would not require replacement or replacement will be simplified. Specifically, the layout for a single transformer, 4 feeder station will be designed for a second transformer and additional 4 feeders. A 4 kV substation will be built to 15 kV clearance standards or a transformer installation will be built with clearances for a larger size transformer.

e. Area study recommendations are comprehensive in nature and are designed to address all system performance and asset condition issues in the area. Load and contingency capacity reviews are conducted in parallel with the asset review. If both types of issues exist, then the Company would progress a recommendation that addresses all of the issues.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

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PUC 2-14
Asset Condition

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, please confirm that there are no Asset Condition Major Projects listed with initial budget entries occurring after FY24. If so, please explain if this is because there are no Major Projects currently expected to initially enter the budget in FY25-FY27 (the remaining years in the forecast on Bates 81), or if there is some other reason.

Response:

There are no Asset Condition Major Projects listed with initial budget entries occurring after FY24 because the Company has not yet determined start dates for projects recommended in the recently completed area studies. Major project schedules in future years will be established as a result of the Company's ongoing prioritization effort of projects resulting from recently completed Area Studies. The results of this prioritization effort including major project schedules are expected to be available when the FY 2024 ISR Plan is presented to the Division.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-15
Asset Condition

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, what is Reserves AR for and why is it forecasted to go from no budget to $4 million in FY24 and then increase to $11.6 million in FY27?

Response:

The "Reserves – AR" line on Attachment 3 is a placeholder for future Asset Condition related work that originates from completed Area Planning Studies and other possible program needs such as the underground cable programs. The Company did not propose a budget in FY 2023 because it believes that it has identified and included the significant asset condition projects arising from Area Planning Studies in the ISR Plan. Since the Company has completed all of its Area Planning Studies, long-term project schedules will be established as a result of the Company's ongoing prioritization effort of recently completed Area Studies. The Company has indicated to the Division that the prioritization effort is expected to be available when the FY 2024 ISR Plan is presented to the Division. At that point, named projects will replace the reserve amounts.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-16
System Capacity and Performance

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, for the two projects in Pre-Project Development (Nasonville Sub and Weaver Hill Road):

a. Please provide a brief description of the projects' need and scope. Please also briefly explain if the current project includes consideration of replacement for asset conditions.
b. Based on current development of the projects, what is the expected useful life of the potential new assets?
c. Are there any changes to conditions (like demand and generation) that at this point could alter the need for these projects? If so, please explain

Response:

a. Nasonville Substation:
The existing Nasonville substation is a 115-13.8kV single transformer substation with four feeders. As explained in response to DIV 5-1, the Nasonville transformer exceeds the 240MWh threshold described in the Distribution Planning criteria. During peak load conditions for loss of the station transformer, there is approximately 13 MW or 350 MWh of unserved load/exposure.

In order to mitigate this contingency load at risk issue, the recommended plan includes installing a new approximately 6 mile 115kV overhead transmission supply line from Woonsocket Substation to Nasonville substation and installing a new transformer and 4 position 13.8kV metalclad bus at Nasonville substation.

Area studies are comprehensive in nature and as such, recommendations address all known asset condition and system capacity and performance issues. However, there were no asset condition issues identified at the Nasonville substation in the Northwest Rhode Island Area study. This project will not address asset condition issues as the project only includes installation of new assets. The details of this plan will be included in the Northwest Rhode Island area study report.

Weaver Hill Road Substation:
The Central Rhode Island West area study identified issues on the Kent County 34.5kV system which include a summer normal overload on the Hopkins Hill 63F6 feeder and the highly loaded 54F1 feeder. Additionally, these circuits are two of the longest distribution feeders in the state of Rhode Island and their 5 year average CKAIFI is greater than 2 and their 5 year average CKAIDI is greater than 180 minutes. They rank in the top 5% of worst

performing feeders for the past five years. A new feeder position is required to address the loading and reliability issues.

The recommended plan includes extending the 3309 and 3310 34.5kV lines from Nooseneck Hill Road and Weaver Hill Road in West Greenwich to a National Grid owned property off pole #64 Weaver Hill Road and installing a new substation at that location. The substation will consist of a 7.5/9.375 MVA transformer and one modular feeder position to be supplied by 3309 preferred/3310 alternate with distribution line work for a new feeder to be made up of parts of Coventry 54F1 and Hopkins Hill 63F6.

Area studies are comprehensive in nature and as such, recommendations address all known asset condition and system capacity and performance issues. Since this project includes installing new infrastructure only, it does not address any known asset condition issues. The details of this plan will be included in the Central Rhode Island West area study report.

b. The Company generally plans for a 20 to 40 year expected useful life for its assets. Electronic assets such as relays and batteries can have a 20-year useful life. Electric assets, such as breakers and regulators, typically have a 30-year useful life. Transformers and mechanical and structural assets typically have a 40-year useful life.

c. There are no changes in demand or generation that at this point could alter the need nor solutions for these projects. These projects were recommendations in the recently completed Northwest Rhode Island and Central Rhode Island West area studies. The area studies considered future load and generation based on latest electric peak forecast reports.

   As explained in response to DIV 1-15, The Company reviews completed Area Study projects before they enter detailed design to validate the need has not changed based on the most recent forecast. If the review indicates that the need or need date of the proposed project(s) has changed or no longer exists, the project(s) will be reanalyzed to align with the new need or need date or when applicable, removed from the plan.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-17

System Capacity and Performance

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, briefly recount all of the different projects and programs related to RTU work National Grid has conducted in the past three years. Please then indicate which of these initiatives or projects are included in the EMS/RTU line item in the table. Please explain what, if any, RTU work will continue after FY25.

Response:

The main program that has RTU related work is the EMS/RTU Program. The following table includes EMS/RTU program projects conducted over the past three years.

Project #	Project Description
C049679	Harrison #32 - EMS Expansion
C049682	Warwick 52 - EMS Expansion
C049800	Coventry #54 - EMS Expansion
C050698	Davisville #84 - EMS Expansion
C074428	EMS EXPANSION - WAMPANOAG 48
C074430	EMS EXPANSION - WOOD RIVER 85
C074431	EMS EXPANSION - BONNET 42
C074433	EMS EXPANSION - BRISTOL 51

RTU work is also completed under other specific work. For example, each volt-var optimization (VVO) project can impact a station's RTU. If a station is rebuilt and it requires an EMS/RTU expansion, that station is removed from the EMS/RTU program and the RTU work is incorporated into the rebuild scope. Therefore, there are numerous substation projects that occurred over the past three years that included some RTU work but were not done under the EMS/RTU Program.

RTU work will continue after FY25. As described above, the RTU is a central piece of equipment in any substation. Many projects require work to modify a RTU. Specifically for the EMS/RTU program, there are a number of stations with planned work that could extend beyond FY25. These stations include Phillipsdale, Wampanaug, Wood River, Anthony, Merton, Tiverton, Apponaug, East George, and Nasonville. We have not determined the scheduling of this work therefore costs associated with this program could increase in FY 2025 and after as that scheduling occurs. Also see the response to DIV 1-12.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-18
System Capacity and Performance

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, what is SCP Reserves for and why is it forecasted to go from no budget to $3.2 million in FY24 and then increase to $15 million in FY27?

Response:

The "Reserves – SCP" line on Attachment 3 is a placeholder for future System Capacity and Performance related work that originates from completed Area Planning Studies, annual capacity reviews and other planning efforts. The Company did not propose a budget in FY 2023 because it believes that it has identified and included the significant reliability and load relief projects. Since the Company has completed all of its Area Planning Studies, long-term project schedules will be established as a result of the Company's ongoing prioritization effort of recently completed Area Studies. The Company has indicated to the Division that the prioritization effort is expected to be available when the FY 2024 ISR Plan is presented to the Division. At that point, named projects will replace the reserve amounts.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-19
System Capacity and Performance

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, please confirm that National Grid's planned VVO capital investment will be completed in FY23. Please explain what changes might occur to require incremental work not shown in this forecast.

Response:

The FY23 forecast for VVO is to complete work on stations identified in prior ISR filings, specifically Dexter, Farnum Pike, Pontiac and Putnam Pike. Work at Dexter, Farnum Pike and Pontiac in FY23 will be minimal spend to complete outstanding work at these substations. However, most of the Putnam Pike work originally planned in FY22 will now occur in FY23, which is estimated to be approximately $0.350 million. Based on current forecasts, the Company does plan to complete all planned VVO investments at these substations in FY23.

As stated in response to DIV 1-13, The Company is pausing additional VVO efforts in Rhode Island until PPL Corporation (PPL) determines what the implementation strategy in RI will be.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

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PUC 2-20

System Capacity and Performance

Request:

Referencing Attachment 3 – Five Year Budget with Details on Bates 81, please confirm that National Grid's planned Storm Hardening work will be completed in FY22. Please explain what changes might occur to require incremental work not shown in this forecast.

Response:

Work will be completed during FY 2022 for this Storm Hardening project. No additional work is planned for this Storm Hardening Project. National Grid continues to evaluate Storm Hardening projects and may propose new projects in the future.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-21
System Capacity and Performance

Request:

Please provide any results or analysis from the previously approved minor storm hardening projects that were initiated in FY 2014 (Tunk Hill Road project which included reconductoring an area from bare conductor to tree wire in a spacer cable arrangement to improve customer reliability and Foster/Clayville, and maybe West Greenwich/Exeter See Docket No. 4473 Plan). Please also provide any results or analysis from those undertaken in NY and MA (Mill Street, Water Street). This question was asked in Docket No. 4783, PUC 2-43).

Response:

For any storm hardening project, the Company does not record incidents where a tree contact may have occurred but there was no outage. As a result, storm hardening post project analysis is limited to tree related outages that did occur.

1. Tunk Hill Road 15F2 Storm Hardening:

The scope of this minor storm hardening (MSH) project was to reconductor a two-mile section of the 15F2 Hope Substation feeder from pole #21 on Hope Furnace Road to pole #87 on Tunk Hill Road. This project was completed in CY 2015.

From calendar years (CY) 2011 to 2015 there were 11 outages that occurred on the Tunk Hill Road section of the 15F2 circuit, mostly caused by tree contact. In comparison, from CY 2016 to 2021, no events occurred due to a tree between pole #21 on Hope Furnace Road to pole #87 on Tunk Hill Road. However, events occurred on Tunk Hill Road beyond the area addressed by this MSH area. The following table compares the two areas:

Calendar Year	# of Tree Events Within MSH Area	# of Tree Events on Tunk Hill Road Beyond MSH Area
2016	0	2
2017	0	0
2018	0	2
2019	0	0
2020	0	6
2021	0	2

While weather patterns and tree growth can vary, it appears that the MSH project successfully reduced tree impacts.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

2. Foster Clayville Minor Storm Hardening:

Feeders 34F1 and 34F3 out of Chopmist Substation were selected to develop a scope of work to increase resiliency to damage during inclement weather in targeted areas. The scope of work has been adjusted over the past few years from pole and conductor hardening to increased sectionalization. The project was completed in CY 2021.

Because the project was recently completed, there is no post project reliability analysis.

Please see below for the two approved storm hardening projects in Massachusetts:

1. Mill Street 912W55:

The project scope included reconductoring lines on Cross Street, Vernon Street and Conant Street in Bridgewater, Massachusetts with spacer cable. The Project was completed in early 2016. The following table shows the number of tree related events since the project was completed.

Calendar Year	# of Tree Events Within MSH Area
2016	0
2017	1
2018	2
2019	0
2020	0
2021	1

This project area experienced 17 tree related outages during the previous 5-year analysis period. Therefore, this project appears to have successfully reduced tree impacts.

2. Water St 910W25:

The project scope included tree wire reconductoring on Mountain Avenue and High Street in Pembroke, Massachusetts. This project was completed in March of 2017. The following table shows the number of tree related events since the project was completed.

Calendar Year	# of Tree Events Within MSH Area
2017	0
2018	1
2019	0
2020	1
2021	0

This project area experienced 6 tree related outages during the previous 5-year analysis period. Therefore, this project appears to have successfully reduced tree impacts.

PUC 2-22
System Reliability Data

Request:

Does National Grid have the ability to present SAIDI and SAIFI data by circuit or some other geographical data? If so, please provide a map of the 2020 SAIDI and SAIFI data shown in the final data points of the figures in Attachment 4 Charts 2 and 3 on Bates 84 and 85—this would be four separate maps.

Response:

Four maps are attached as separate files to present SAIFI and SAIDI by feeders with and without Major Storms in 2020.

Please see:

Attachment PUC 2-22-1 – Narragansett Electric - 2020 SAIDI - By Feeder - With Major Storms
Attachment PUC 2-22-2 – Narragansett Electric - 2020 SAIDI - By Feeder - Without Major Storms
Attachment PUC 2-22-3 – Narragansett Electric - 2020 SAIFI - By Feeder - With Major Storms
Attachment PUC 2-22-4 – Narragansett Electric - 2020 SAIFI - By Feeder - Without Major Storms

Please note that due to the very large electronic file sizes associated with these attachments, they will be sent separately.

PUC 2-23
System Reliability Data

Request:

Does National Grid track the amount of non-capital spending on restoration and the resulting restoration time or average restoration time? If the data is tracked, please provide it for all calendar years available from 2001 to 2020 (as in the figures provided in the System Reliability Data section of the Plan). If not, does National Grid have the ability to track this data?

Response:

The Company does not track the non-capital spending on restoration work as compared with the resulting restoration or average restoration time.

While the Company does have restoration times per outage event and/or the overall restoration time for a specific major storm event, the Company does not have the ability to separate capital from non-capital restoration times.

The most variability in restoration costs pertain to storm events. A substantial portion of costs incurred related to storm events relates to outside crew costs. The acquisition of outside crews is driven by the forecasted weather and anticipated impacts and actual impact of that weather on the Company's electric infrastructure, which can vary significantly with each event. While we could possibly track total storm costs over total restoration times, there would likely be other information around forecasted and actual weather impacts on the electric system that would be more useful in determining future storm planning.

PUC 2-24
System Reliability Data

Request:

If National Grid tracks non-capital spending per restoration time, and can show this data geographically, please provide such a data map.

Response:

As indicated in response to PUC 2-23, the Company does not track non-capital spending per restoration time.

PUC 2-25

System Reliability Data

Request:

Referencing the data represented in Chart 4 on Bates 86, what does the category "Sub-Transmission" include? For example, does it include tree contact, but on sub-transmission lines?

Response:

Category Sub-Transmission includes any event that affects a Sub-Transmission line. This includes the events that are caused by tree contact on sub-transmission lines.

Prepared by or under the supervision of: Bertram Stewart III

PUC 2-26
System Reliability Data

Request:

Does the category tree include tree contact caused by human error?

Response:
Category tree includes outages that are caused by tree growth, tree fell, broken tree limb and tree vines. This does not included tree contact by human error.

PUC 2-27
System Reliability Data

Request:

Referencing the data represented in Chart 4 on Bates 86, please provide SAIDI and SAIFI for CY08 to CY20 excluding outages for the category "Tree." Please also remove any other tree-contact incident if they are included in Sub-Transmission. Please do not remove any tree-incident that is ultimately caused by human error, if any such incidents are included in these categories.

Response:

Here is the SAIFI and SAIDI summary for CY2008 to CY2020 excluding "Tree" Category and excluding any tree caused Sub-Transmission related outages.

Year	SAIFI	SAIDI
2008	0.802	45.33
2009	0.690	38.19
2010	0.871	57.92
2011	0.723	47.88
2012	0.707	45.89
2013	0.607	43.61
2014	0.629	42.51
2015	0.779	48.58
2016	0.774	48.78
2017	0.559	40.03
2018	0.732	41.92
2019	0.742	41.06
2020	0.642	42.17

Prepared by or under the supervision of: Bertram Stewart III

PUC 2-28
System Reliability Data

Request:

Regarding the benefit cost analysis provided for 3763 Line Structure Replacements, particularly the information provided on Bates 93, how is National Grid's comment regarding the quantification of distribution system benefits and customer reliability and resiliency impacts consistent with reliability benefits presented in the most recent Energy Efficiency Program Plan (Docket 5189)? In particular, explain how the Energy Efficiency program managers able to quantify reliability for that program, but ISR program managers are not.

Response:

The reliability benefit quantified by Energy Efficiency program managers is system-wide calculated benefit that can be applied to small and widely distributed energy efficiency efforts. The reliability benefit associated with this specific distribution project within the ISR is that project's direct reliability benefit as calculated by historical performance. For example, a sub-transmission line could have asset condition issues but no historical reliability issues. The lack of reliability impacts could be from no direct events or it could be that the line is part of looped system such that when line events occur no customers are impacted. While it can be argued that the existence of the line provides a theoretical reliability benefits, the Company does not believe that every time a structure is replaced on that line, the theoretical benefit can be claimed repeatedly. Therefore, this specific asset condition project has a 'not quantifiable' reliability benefit. Alternately the Company could state that the reliability benefit for this project is quantifiable and zero, however there would be no actual quantification because there is no reliability data to calculate.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-29
Vegetation Management

Request:

Referencing the data shown in Chart 2 on Bates 106, please confirm that there is no definitional control group against which to compare areas that have received EHTM work in the data presented, or please explain what National Grid's understanding of the control group is.

Response:

National Grid does compare the reliability performance of circuits receiving EHTM work to all circuits in Rhode Island. Chart 4 on Bates 109 shows how the EHTM circuits have performed each year compared to all circuits in Rhode Island. The chart shows that circuits receiving EHTM work have significant reliability benefits compared to the rest of the state.

PUC 2-30
Vegetation Management

Request:

What is the definition of the area that comprises the data shown in Chart 2 on Bates 106? Is it a circuit that has received EHTM work, or some other area?

Response:

Chart 2 is a summary of all circuits receiving EHTM work in each fiscal year from 2008 to 2020.

Prepared by or under the supervision of: Ryan Moe

PUC 2-31
Vegetation Management

Request:

Referencing the data shown in Chart 3 on Bates 106, please confirm that there is no definitional control group against which to compare areas that have received cycle pruning work in the data presented, or please explain what National Grid's understanding of the control group is.

Response:

No, National Grid has not created a control group or done any comparison similar to that in Chart 4 on Bates 109 for the data shown in Chart 3 on Bates page 107.

Prepared by or under the supervision of: Ryan Moe

PUC 2-32
Vegetation Management

Request:

Referencing the data shown in Chart 4 on Bates 109, does the data in the Average Annual CI Pre-Project represent one fiscal year of data? If so, how should the data in this column relate to the interruption data on Bates 88 and 89?

Response:

No, the data in the Average Annual CI Pre-Project column is the three-year average of CI for EHTM feeders and for all feeders in Rhode Island prior to the project year. The three-year average does not match the three prior fiscal year average from the interruption data on Bates 88 and 89 because the data was derived differently. When the state-wide data for Chart 4 on Bates 109 was developed, it included all tree-related outages, including outages on the sub-transmission and the transmission systems, and at substations. The charts on Bates 88 and 89 separate those tree-related outages into the sub-transmission, transmission, and substation categories. Due to the differences in categorization the numbers do not match. Also, an updated chart 4 has been provided removing the tree-related outages on the transmission system from the data so that the impact of the Vegetation Management program in the ISR can be separately identified from the impact of including the Transmission impact.

Section 3 – Chart 4
EHTM Program Benefits Compared to Statewide Performance

	Average Annual CI Pre-Project	Average Annual CI - Post- Project (all full years available)	% Improvement
FY 2008 (3 years of data post-project)			
EHTM Feeders	22,127	9,734	56%
All RI Feeders (State-wide)	104,037	88,303	15%
FY 2009 (3 years of data post-project)			
EHTM Feeders	32,092	10,511	67%
All RI Feeders (State-wide)	119,104	92,553	22%
FY 2010 (3 years of data post-project)			
EHTM Feeders	50,145	10,670	79%
All RI Feeders (State-wide)	100,629	94,614	6%
FY 2011 (3 years of data post-project)			
EHTM Feeders	1,133	271	76%
All RI Feeders (State-wide)	94,475	81,203	14%
FY 2012 (3 years of data post-project)			
EHTM Feeders	8,601	1,784	79%
All RI Feeders (State-wide)	88,303	72,480	18%
FY 2013 (3 years of data post-project)			
EHTM Feeders	15,109	4,541	70%
All RI Feeders (State-wide)	92,553	74,842	19%
FY 2014 (3 years of data post-project)			
EHTM Feeders	13,048	4,408	66%
All RI Feeders (State-wide)	94,614	89,075	6%
FY 2015 (3 years of data post-project)			
EHTM Feeders	10,902	13,125	-20%
All RI Feeders (State-wide)	81,203	97,246	-20%

PUC 2-32, page 3

FY 2016 (3 years of data post-project)			
EHTM Feeders	4,060	520	87%
All RI Feeders (State-wide)	72,480	114,616	-58%
FY 2017 (3 years of data post-project)			
EHTM Feeders	8,861	7,171	19%
All RI Feeders (State-wide)	74,842	123,885	-66%
FY 2018 (3 years of data post-project)			
EHTM Feeders	8,573	4,579	47%
All RI Feeders (State-wide)	89,075	147,531	-66%
FY 2019 (2 years of data post-project)			
EHTM Feeders	8,549	3,854	55%
All RI Feeders (State-wide)	97,246	145,245	-49%
FY 2020 (1 year of data post-project)			
EHTM Feeders	42,021	40,551	3%
All RI Feeders (State-wide)	114,616	162,764	-42%

Prepared by or under the supervision of: Ryan Moe

PUC 2-33
Vegetation Management

Request:

Please resubmit the table on Bates 112 showing the final row.

Response:

Please see tables below.

PUC 2-33, page 2

Circuit	Annual AVG Repair Costs Pre-Project	Annual AVG Repair Costs Post-Project (3 Years Max.)	% Improvement
49_53_13F2	$ 566	$ 229	60%
49_53_34F2	$ 1,877	$ 601.32	68%
49_53_51F1	$ 1,938	$ 722	63%
49_53_69F1	$ 203	$ 655	-223%
49_56_33F4	$ 745	$ 1,137	-53%
49_56_54F1	$ 6,040	$ 5,701.32	6%
49_56_63F6	$ 916	$ 1,042	-14%
49_53_102W51	$ 206	$ -	100%
49_53_112W42	$ 677	$ 419	38%
49_53_2291	$ -	$ -	-
49_53_23F1	$ 1,289	$ 341	74%
49_53_38F1	$ 2,014	$ 2,176	-8%
49_53_5F4	$ 1,166	$ 206	82%
49_56_22F4	$ 719	$ 588	18%
49_56_30F1	$ 3,959	$ 772	80%
49_56_52F3	$ 2,069	$ 660	68%
49_53_108W62	$ 41	$ -	100%
49_53_20F2	$ 63	$ -	100%
49_53_38F5	$ 1,504	$ 2,449	-63%
49_53_5F2	$ 1,202	$ 1,330	-11%
49_53_5F3	$ 538	$ 951	-77%
49_53_7F1	$ 41	$ 332	-719%
49_56_16F1	$ 1,095	$ 1,845	-69%
49_56_17F2	$ 462	$ 1,817	-293%
49_56_42F1	$ 1,617	$ 1,601	1%
49_56_43F1	$ 3,210	$ 5,764	-80%
49_56_46F2	$ 3,343	$ 3,141	6%
49_56_59F4	$ 462	$ 319	31%
49_56_72F3	$ 978	$ 837	14%
49_53_38F5	$ 1,129	$ 3,970	-252%
49_53_112W44	$ 6,381	$ 4,561	29%
49_53_126W41	$ 3,572	$ 4,886	-37%
49_53_15F1	$ 1,736	$ 547	68%
49_53_34F3	$ 8,601	$ 9,928	-15%
49_56_43F1	$ 11,830	$ 8,906	25%
49_56_59F4	$ 2,785	$ 2,093	25%
49_53_107W83	$ 99	$ 656	-563%
49_53_126W41	$ 5,213	$ 5,863	-12%
49_53_15F1	$ 5,805	$ 2,530	56%
49_53_18F6	$ 6,095	$ 2,639	57%
49_53_27F1	$ 1,669	$ 1,688	-1%
49_53_38F4	$ 3,192	$ 2,262	29%
49_53_4F1	$ 2,983	$ 1,607	46%
49_53_4F2	$ 6,061	$ 4,666	23%
49_56_14F1	$ 2,271	$ 1,630	28%
49_56_22F2	$ 3,261	$ 570	83%
49_56_57J2	$ 175	$ 341	-95%
49_56_57J5	$ 364	$ 351	4%
49_56_68F3	$ 8,453	$ 8,705	-3%

Prepared by or under the supervision of: Ryan Moe

PUC 2-33, page 3

49_56_88F5	$ 7,802	$ 11,634	-49%
49_53_112W42	$ 4,250	$ 2,212	48%
49_53_112W41	$ 1,231	$ 785	36%
49_53_18F7	$ 2,031	$ 732	64%
49_56_33F3	$ 10,254	$ 9,544	7%
49_56_33F1	$ 4,860	$ 3,033	38%
49_56_33F2	$ 3,285	$ 844	74%
49_56_38K23	$ -	$ -	-
49_53_21F1	$ 3,699	$ 4,764	-29%
49_53_21F2	$ 4,327	$ 2,988	31%
49_53_21F4	$ 1,260	$ 2,377	-89%
49_53_34F2	$ 16,866	$ 14,017	17%
49_53_38F1	$ 11,533	$ 17,810	-54%
49_56_54F1	$ 18,195	$ 23,325	-28%
49_56_63F3	$ 5,167	$ 5,980	-16%
49_56_63F6	$ 9,486	$ 12,480	-32%
49_56_85T3	$ 10,222	$ 7,243	29%
49_56_40F1	$ 122	$ -	100%
49_56_41F1	$ 11,113	$ 2,056	81%
49_56_88F3	$ 8,613	$ 7,598	12%
49_56_37W41	$ 1,689	$ 1,984	-17%
49_56_37W42	$ 969	$ 206	79%
49_56_37W43	$ 512	$ 256	50%
49_53_34F1	$ 14,073	$ 30,489	-117%
49_56_30F1	$ 4,591	$ 2,248	51%
49_56_30F2	$ 12,663	$ 11,714	7%
49_56_46F3	$ 3,339	$ 1,458	56%
49_56_88F1	$ 5,590	$ 6,657	-19%
49_56_33F1	$ 3,037	$ 1,046	66%
49_56_33F2	$ 1,373	$ 1,850	-35%
49_56_33F3	$ 8,298	$ 5,024	39%
49_56_33F4	$ 9,467	$ 11,142	-18%
49_56_88F1	$ 6,755	$ 9,276	-37%
49_56_88F5	$ 6,018	$ 5,459	9%
49_53_15F2	$ 9,987	$ 8,511	15%
49_56_33F4	$ 15,038	$ 12,870	14%
49_56_59F1	$ 2,556	$ 3,868	-51%
49_56_68F1	$ 9,492	$ 16,542	-74%
49_53_112W43	$ 2,511	$ -	100%
49_53_127W40	$ 12,163	$ 13,749	-13%
49_53_34F1	$ 30,556	$ 41,916	-37%
49_53_34F2	$ 24,921	$ 26,330	-6%
49_53_34F3	$ 10,700	$ 17,741	-66%
49_53_38F1	$ 21,270	$ 17,277	19%
49_53_26W1	$ 6,387	$ 11,376	-78%
49_53_15F1	$ 2,344	$ -	100%
49_53_15F2	$ 9,511	$ 10,927	-15%
49_56_17F2	$ 6,723	$ 1,090	84%
49_56_155F6	$ 7,177	$ 13,597	-89%
49_56_155F8	$ 18,655	$ 18,890	-1%
49_56_30F2	$ 10,271	$ 24,862	-142%
49_56_54F1	$ 25,312	$ 28,404	-12%
49_56_63F6	$ 25,398	$ 24,938	2%
49_56_46F1	$ 2,898	$ 2,720	6%
49_56_59F1	$ 3,557	$ 5,864	-65%
49_56_59F3	$ 8,774	$ 18,650	-113%
49_56_63F3	$ 7,914	$ 13,927	-76%
49_53_127W41	$ 3,298	$ 10,657	-223%
49_56_85T3	$ 5,005	$ -	100%
49_56_68F1	$ 13,270	$ 21,117	-59%
49_56_68F2	$ 4,962	$ 22,142	-346%
49_56_68F3	$ 3,814	$ 3,499	8%
49_56_68F4	$ 8,668	$ 8,175	6%
Totals	**$ 646,441**	**$ 721,900**	**-12%**

Prepared by or under the supervision of: Ryan Moe

PUC 2-34
Vegetation Management

Request:

Please review the "cost-benefit" data National Grid presents on Bates 113 and 114, and respond to the following to the extent possible: based on National Grids presentation of the effectiveness of the cycle pruning and EHTM program, in what years would eliminating either of these programs increase National Grid's SAIDI and SAIFI scores such that National Grid would exceed the allowed threshold?

Response:

There is no way to know with certainty if the elimination of the EHTM program in any given year would cause National Grid to exceed the allowed thresholds for SAIDI or SAIFI. However, there are assumptions we would make to perform this type of analysis.

To do this analysis for the EHTM program, the following assumptions were used: 1) Each hazard tree removed would have caused an outage that year, 2) the interruption impact was calculated using the average number of customers interrupted (CI) and customer minutes interrupted (CMI) per tree event on three-phase portions of distribution circuits from calendar years 2007 to 2019, 3) the CI and CMI avoided was calculated by multiplying the number of hazard trees removed by the average CI and CMI per event, 4) the SAIFI and SAIDI impacts from those avoided outages were added to the SAIFI and SAIDI from the corresponding calendar year (ie. fiscal year 2008 is added to calendar year 2007) because nine out of the twelve months in fiscal year 2008 are in calendar year 2007. The result of this analysis shows that in every year from 2008 to 2020, if the hazard trees were not removed, the Company would have significantly exceeded the targets for SAIFI and SAIDI. Please see Attachment PUC 2-34 for the full table. Even allowing for the unpredictability for the timing of each tree failure, and the differences from calendar year to fiscal year, the results show clearly that without performing the EHTM program, it is extremely likely that National Grid would not be able to meet its SAIFI and SAIDI targets for any given year.

Cycle pruning is more difficult to evaluate because each tree that is pruned doesn't necessarily mean that an outage has been avoided. Cycle pruning is a maintenance program and is considered an industry best-practice. While there is some reliability benefit, it is designed to maintain clearances between the conductors and vegetation for public and worker safety, easy access for maintenance and repairs, and to maintain reliability. The consequences of skipping a single year of pruning are not likely to have a significant reliability impact at the system level. However, the compounded impacts over time would be significant. Industry research shows that deferring pruning for one year beyond the ideal cycle results in a 21% increase in costs to prune the following year.[1] Skipping one year of pruning, would require several years to catch up and return to a normal cycle. Costs would increase, and likely more circuits would need to be deferred to the next fiscal year. In addition, due to an increasing volume of vegetation which will be in contact with the conductors, it may be necessary to take outages to safely complete pruning work, not counting the additional outages that will be caused if the vegetation grows through the wires. Due to this complexity and the lack of data to provide estimates, National Grid cannot quantify the reliability impacts of skipping an entire year of cycle pruning or predict which years it would have exceeded the SAIFI and SAIDI thresholds.

[1] *Journal of Arboriculture* May 1997 – "The Economic Impacts of Deferring Electric Utility Tree Maintenance" - p.110

Fiscal Year	Avg CI/Event	Avg CMI/Event	# of Trees Removed (Outages Avoided)	CI Avoided	Incremental SAIFI Impact	CMI Avoided	Incremental SAIDI Impact	Calendar Year	Actual SAIFI (CY)	Adjusted SAIFI	SAIFI Target	Actual SAIDI (CY)	Adjusted SAIDI	SAIDI Target
2008	459.1	37,195.71	1,303	598,207.30	1.21	48,466,010.13	97.97	2007	0.92	2.13	1.05	59.02	156.99	71.9
2009	459.1	37,195.71	920	422,372.00	0.85	34,220,053.20	69.17	2008	1.01	1.86	1.05	64.44	133.61	71.9
2010	459.1	37,195.71	558	256,177.80	0.52	20,755,206.18	41.96	2009	0.85	1.37	1.05	51.08	93.04	71.9
2011	459.1	37,195.71	415	190,526.50	0.39	15,436,219.65	31.20	2010	1.07	1.46	1.05	76.3	107.50	71.9
2012	459.1	37,195.71	1,040	477,464.00	0.97	38,683,538.40	78.20	2011	0.86	1.83	1.05	60.7	138.90	71.9
2013	459.1	37,195.71	942	432,472.20	0.87	35,038,358.82	70.83	2012	0.9	1.77	1.05	65.99	136.82	71.9
2014	459.1	37,195.71	701	321,829.10	0.65	26,074,192.71	52.71	2013	0.72	1.37	1.05	57.28	109.99	71.9
2015	459.1	37,195.71	1,181	542,197.10	1.10	43,928,133.51	88.80	2014	0.78	1.88	1.05	54.06	142.86	71.9
2016	459.1	37,195.71	862	395,744.20	0.80	32,062,702.02	64.81	2015	0.94	1.74	1.05	64.63	129.44	71.9
2017	459.1	37,195.71	975	447,622.50	0.90	36,265,817.25	73.31	2016	0.97	1.87	1.05	69.13	142.44	71.9
2018	459.1	37,195.71	1,629	747,873.90	1.51	60,591,811.59	122.48	2017	0.78	2.29	1.05	59.1	181.58	71.9
2019	459.1	37,195.71	1,663	763,483.30	1.54	61,856,465.73	125.04	2018	1	2.54	1.05	65.11	190.15	71.9
2020	459.1	37,195.71	2,995	1,375,004.50	2.78	111,401,151.45	225.19	2019	1.02	3.80	1.05	68.2	293.39	71.9

PUC 2-35
Inspection and Maintenance

Request:

Referencing the Plan on Bates 116:

a. What is the cost of a site visit for Level 9 priority conditions not completed within 90 days?
b. How many such visits were completed per year in the previous three years for which data is available?
c. What was the average number of site visits per identified condition for the previous three years for which data is available?
d. What was the total cost of site visits for the previous three years for which data is available?

Response:

a. The Company does not track site visits between the time a Level 9 temporary repair is made and when the permanent repair is made. The inspection cost for a site visit to initially identify the issue is approximately $11 excluding benefits and overheads. This is based on the hourly cost of the inspectors and a 15 minute per pole inspection time. There is also a site visit by a supervisor as a pre-check to construction, which is approximately $20 excluding benefits and overheads per pole.

b. This data is not tracked; however, 99 Level 9 issues were identified in the previous three years (FY19-FY21).

c. This data is not tracked, however each Level 9 site is visited three times prior to completion of the work: once when found, pre-check, and crew repair. Documentation of the temporary repair often includes detailed notes and photographs that support the future permanent repair by the design department.

d. The inspection costs for the previous three years are estimated at:
   2019 – (27) x $11 = $297
   2020 – (52) x $11 = $572
   2021 – (20) x $11 = $220
   Total cost = $1089
   The pre-check costs for the previous three years are estimated at:
   2019 – (27) x $20 = $540
   2020 – (52) x $20 = $1040
   2021 – (20) x $20 = $400
   Total cost = $1980
   The total overall site visit cost is $3069.

Prepared by or under the supervision of: Christopher Valentino and Kevin Hellmuth

PUC 2-36
Inspection and Maintenance

Request:

How was the $25 thousand for the Long Range Plan used in FY22, and how will it be used in FY23?

Response:

The System Planning & Protection Coordination Study budget of $25,000 was established to allow the Company recovery of costs associated with Area Planning Studies that did not result in capital projects. All studies completed during FY 2022 resulted in capital projects, therefore, no costs will be charged to this line item during FY 2022. Since all Area Planning Studies were completed during FY 2022, the Company does not anticipate any costs being charged to this line item in FY 2023.

Prepared by or under the supervision of: Patricia Easterly

PUC 2-37
Coordination of Load and Distributed Generation Planning and Investment

Request:

Please provide a listing and description for all DG projects for which funding is included in the FY 2023 Electric ISR Plan. Please also indicate where the Company is conducting simultaneous system improvement work for which the DG customer is not responsible. If there have been no such instances, please explain why.

Response:

There are no DG projects for which funding is included in the FY2023 Electric ISR plan because there are no system improvement projects associated with DG studies identified for construction in FY23. However, the Company is continuously performing DG studies, and it is possible system improvement work will be identified and required as part of a DG project as work progresses throughout the fiscal year.

The FY 2023 ISR Plan has a $1 million estimate for DG projects, similar to FY 2021 and FY 2022. This estimate assumes that there may be timing differences between capital spending and when Contributions in aid of Construction (CIAC) from customers are reflected in the capital spending, which the Company expects to be a minimal amount.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

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PUC 2-38
Coordination of Load and Distributed Generation Planning and Investment

Request:

Referencing PUC 1-19, please quote the language from the DG Interconnection and load interconnection tariffs that prohibits the Company from making proactive investments to facilitate DG interconnections.

Response:

Based on a review of the Standards for Connecting Distributed Generation, R.I.P.U.C. No. 2244, (the "Interconnection Tariff"), there is no language in the Interconnection Tariff that prohibits the Company from making proactive investments. The Company will file a revised response to PUC 1-19 clarifying the sentence that suggests there is an express prohibition. Standard utility capital programs and rate making depend upon when an investment is 'used and useful'. Unless a clear need exists for a capital investment, then there is a real risk that a regulatory body will dis-allow such an investment if it is not considered 'used and useful'. Proactive investment to make the electric system 'DG ready' is challenging because it is very difficult to predict exactly where such investments will occur. Without a coordinated state-wide effort to specifically identify key attributes, such as appropriate locations, meeting the 'used and useful' criteria with pro-active investments would be highly uncertain.

Prepared by or under the supervision of: Timothy Roughan

PUC 2-39
Coordination of Load and Distributed Generation Planning and Investment

Request:

Referencing PUC 1-19, please explain the Company's initial steps to improve its planning tools to better analyze DG and DER impacts on the system.

Response:

The Company is exploring 8760-hour per year analysis using custom spreadsheet forms and current CYME model capabilities. The spreadsheet forms were developed to help teach planners: 1) the importance of modeling each technology separately; 2) typical load cycles for each technology; 3) how these typical load cycles can vary; and 4) how it all adds up to the net power curve. It is important to note that the Company does not have typical load cycles developed for technologies like heat pumps. The latest CYME radial distribution analysis software has the ability to perform loadflow with profiles. The Company has explored using 8760-hour profiles within this module, however the data analysis time, storage requirements, and subsequent amount of data to analyze is substantial. The Company has begun these initial steps as a result of the rising complications in DER analysis as DER penetration increases.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

PUC 2-40
Coordination of Load and Distributed Generation Planning and Investment

Request:

Referencing PUC 1-22, what are the projects described in the second paragraph of the response?

Response:

The three projects described in the second paragraph of the response to PUC 1-22 are explained in more detail below. All three of the alternatives explained below considered pending Distributed Generation customer driven projects during solution development in their respective area studies.

Pine Hill Substation Alternative - Central Rhode Island West area study
As explained in response to PUC 2-16a, the Central Rhode Island West area study identified issues on the Kent County 34.5kV system which include a summer normal overload on the Hopkins Hill 63F6 feeder and the highly loaded 54F1 feeder. Additionally, these circuits are two of the longest distribution feeders in the state of Rhode Island and their 5 year average CKAIFI is greater than 2 and their 5 year average CKAIDI is greater than 180 minutes. They rank in the top 5% of worst performing feeders for the past five years.

This project is one of the alternatives developed in the Central Rhode Island West area study to address these issues. This is the alternative to the Weaver Hill Road substation described in PUC2-16a.

This alternative would construct a new supply line utilizing the new proposed Wickford Junction substation. The new proposed Wickford Junction substation projects includes building a new substation solely to interconnect Distributed Generation PV sites.

The scope of this alternative would include:

- Extending the 3310 line for 3.25 miles from Rtes. 3 and 102, Exeter to a National Grid owned property at the intersection of New London Turnpike and Bell Schoolhouse Road, Exeter referred to as Pine Hill Substation.
- Installing a new 34.5 kV line for 7.5 miles from the new proposed Wickford Junction substation to Pine Hill substation.
- Installing a 7.5/9.375 MVA transformer and one modular feeder position to be supplied by the 3310 preferred and Wickford Junction line alternate.
- Performing distribution line work for a new feeder to pick up portions of Coventry 54F1 and Hopkins Hill 63F6.

This alternative was not recommended as it was not the least cost fit for purpose option. This alternative will be described in more detail in the Central Rhode Island West area study report.

Nasonville Substation Alternative 4 – Northwest Rhode Island area study:
As explained in response to DIV 5-1, the Nasonville transformer exceeds the 240MWh threshold described in the Distribution Planning criteria. During peak load conditions for loss of the station transformer, there is approximately 13 MW or 350 MWhr of unserved load/exposure. There were multiple alternatives developed in the Northwest Rhode Island area study to address this contingency load at risk issue (see response to DIV 5-1).

One of the alternatives would utilize a new overhead supply line from the proposed Iron Mine Hill substation. The new proposed Iron Mine Hill substation project includes building a new substation solely to interconnect Distributed Generation PV sites. The company did consider this new proposed substation in the Northwest Rhode Island area study to solve this Nasonville transformer contingency load at risk issue.

This alternative would include installing a new approximately 6.5 mile 34.5kV overhead supply line from the new proposed Iron Mine Hill substation to Nasonville substation and installing a new transformer and 4 position 13kV metalclad bus at Nasonville substation.

This alternative was not recommended as it was not the least cost fit for purpose option. This alternative will be explained in more detail in the Northwest Rhode Island area study report.

Tiverton 33F6 circuit – Tiverton area study:
As explained in response to DIV 5-1, all four Tiverton 12.47kV feeders exceed the 16MWh threshold described in the Distribution Planning criteria. Installing a new 33F6 circuit at Tiverton substation is the recommended alternative to address these issues.

There are two Distributed Generation (DG) projects currently in design that require the construction of a new 33F6 circuit for interconnection. If the DG project does not proceed, this 33F6 circuit will still be needed to address the area contingency loading concerns, and the same route would be followed as the least-cost solution. However, the new 33F6 will need to be extended past the proposed DG site to address the contingency load-at-risk issue.

Since the DG project is on a different schedule, which is earlier than the Company's recommended plan, the DG developer will be responsible for the costs to serve their project. Cost sharing will apply to this potion of work once the 33F6 circuit is being used to serve load as per the Standards for Interconnecting Distributed Generation (RIPUC 2244) Section 5.4 (b).

This project will be described in more detail in the Tiverton area study report.

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable