nationalgrid

Raquel Webster
Senior Counsel

December 8, 2017

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4756 - 2018 System Reliability Procurement Report
Responses to PUC Data Requests – Set 1

Dear Ms. Massaro:

I have enclosed ten copies of National Grid's[1] responses to the PUC's first set of data requests in the above-referenced docket.

Thank you for your attention to this filing. If you have any questions, please contact me at 781-907-2121.

Sincerely,

Raquel Webster

cc: Docket 4756 Service List
Jon Hagopian, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

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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

December 8, 2017
Date

Docket No. 4755 - National Grid – Energy Efficiency Program Plan for 2018
Docket No. 4756 - National Grid – 2018 System Reliability Procurement Report (SRP)
Service list updated 11/27/17

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PUC 1-1

Request:

What costs are associated with deferral of the feeder over four years (2018-2021)?

Response:

The costs incurred to defer the Tiverton substation feeder from 2018 through 2021 are $438,000. The avoided revenue requirement collections associated with that feeder deferral are $647,599.

Prepared by or under the supervision of: Lindsay Foley

PUC 1-2

Request:

Regarding the Tiverton Pilot, the Commission is interested in understanding how the actual load and projections for load growth changed in the pilot area (or feeder) since 2011. In particular, the Commission is interested in understanding what role changes in the forecast for load growth allowed the deferment of the distribution system upgrade. On a single chart with axes of kilowatt versus years 2011 through 2025, please plot:

a. The actual feeder rating or load limit the pilot was attempting to avoid exceeding.
b. The actual peak in 2011 through the year the most current data is available.
c. The load growth curve forecast for the pilot area (or feeder) in 2011. For clarity, this line should indicate what National Grid forecasted, in the year 2011, would be the loading in the pilot area for years 2012 through 2025.
d. Please repeat the request in part c above, but for years 2012 through the most recent projection. Please plot each annual forecast in a different color.
e. Please provide the data in parts c and d in a table, with rows incrementing calendar years, and columns incrementing project years. Please add a column for the information in part b.

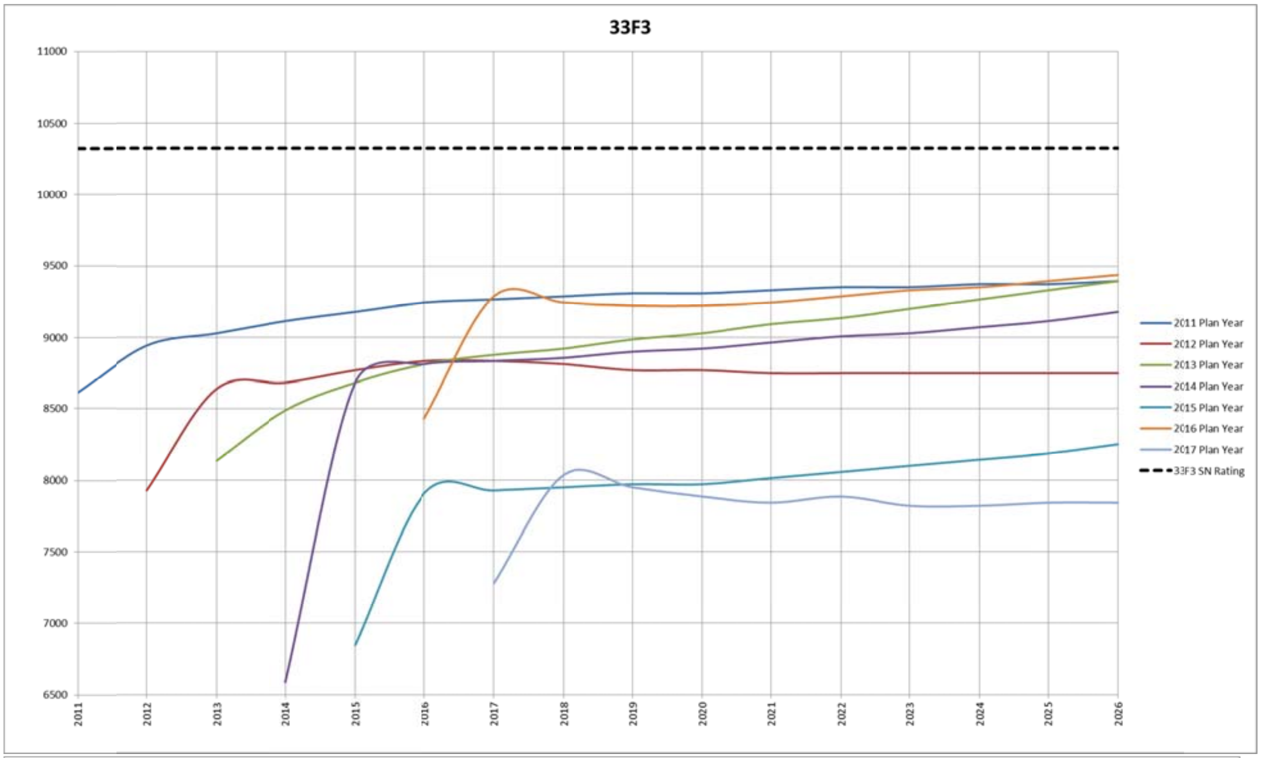
Response:

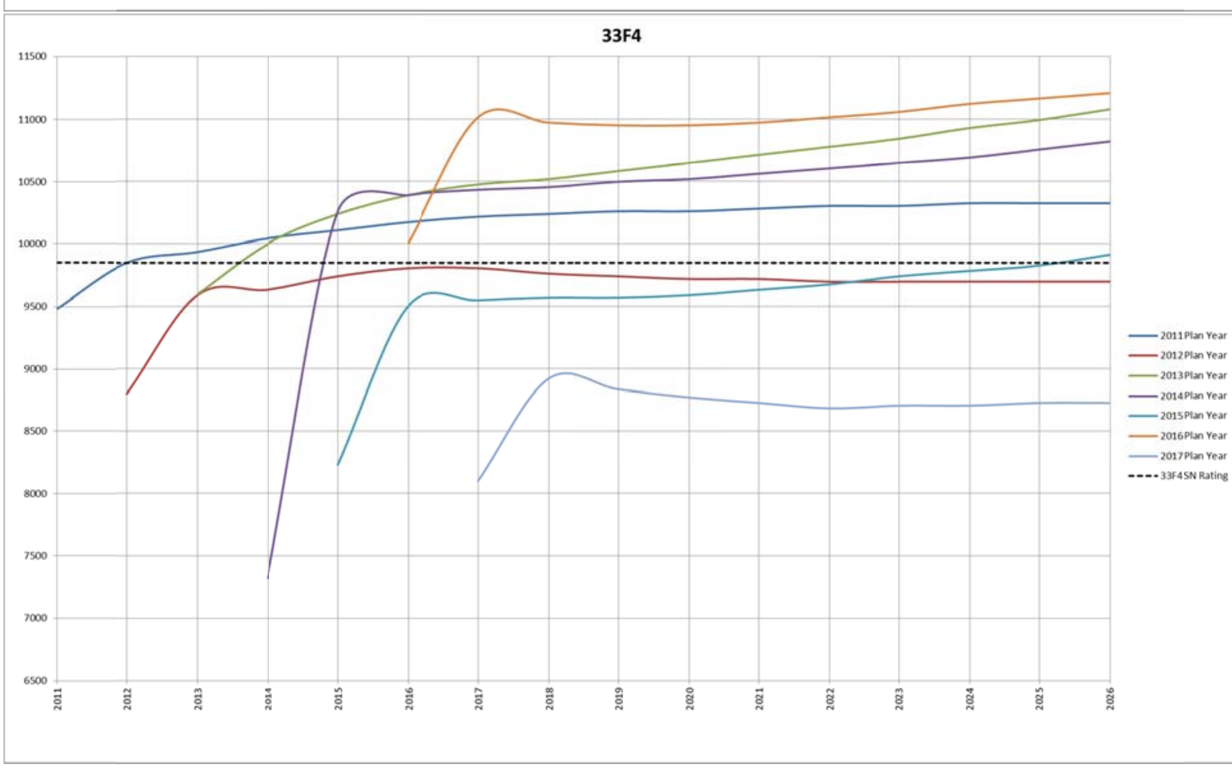
The pilot area is considered to be the area served by the 33F3 and 33F4 circuits from the Tiverton Substation. The 33F4 circuit was the one projected to exceed its summer normal (SN) rating. Please see the graphs below for the two circuits showing:

a. The actual feeder rating or load limit the pilot was attempting to avoid exceeding. The load limit is shown as a dashed horizontal line in the graphs.
b. The actual peak in 2011 through the year the most current data is available. Actual peaks are shown as the first point in each curve.
c. The load growth curve forecast for the pilot area (or feeder) in 2011 through 2025.
d. The load growth curve forecast for the pilot area (or feeder) in 2012, 2013, 2014, 2015, 2016, and 2017. Each curve is forecasted through 2025 and shown in a different color. The load growth curves include a first year weather adjustment to modify the actual values to an extreme summer forecast

Attachment PUC1-2 includes the data described in parts a, b, c, and d above in tabular format with rows incrementing calendar years, and columns incrementing project years.

Prepared by or under the supervision of: Ryan Constable





Prepared by or under the supervision of: Ryan Constable

	2011 Planning Year			2012 Planning Year			2013 Planning Year			2014 Planning Year			2015 Planning Year			2016 Planning Year			2017 Planning Year		
	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA	Growth Rates	33F3 Load kVA	33F4 Load kVA
Rating		10325	9850		10325	9850		10325	9850		10325	9850		10325	9850		10325	9850		10325	9850
2011	Actual	8611	9482																		
2012	3.8%	8942	9849	Actual	7927	8798															
2013	1.0%	9028	9935	9.0%	8639	9590	Actual	8136	9597												
2014	1.0%	9115	10043	0.5%	8683	9633	4.3%	8488	10000	Actual	6588	7322									
2015	0.7%	9179	10108	1.0%	8769	9741	2.3%	8683	10238	25.5%	8683	10259	Actual	6847	8229						
2016	0.6%	9244	10173	0.7%	8834	9806	1.4%	8812	10389	1.1%	8812	10389	15.6%	7905	9503	Actual	8431	10007			
2017	0.4%	9266	10216	0.0%	8834	9806	0.9%	8877	10475	0.3%	8834	10432	0.3%	7927	9547	10.2%	9287	11015	Actual	7279	8100
2018	0.2%	9287	10238	-0.3%	8812	9763	0.5%	8920	10519	0.1%	8855	10454	0.2%	7948	9568	-0.5%	9244	10972	10.3%	8035	8920
2019	0.2%	9309	10259	-0.3%	8769	9741	0.6%	8985	10583	0.2%	8899	10497	0.1%	7970	9568	-0.2%	9223	10951	-1.0%	7948	8834
2020	0.1%	9309	10259	-0.2%	8769	9719	0.6%	9028	10648	0.3%	8920	10519	0.2%	7970	9590	0.0%	9223	10951	-0.8%	7884	8769
2021	0.1%	9331	10281	-0.1%	8747	9719	0.6%	9093	10713	0.3%	8963	10562	0.5%	8013	9633	0.3%	9244	10972	-0.6%	7840	8726
2022	0.2%	9352	10303	-0.1%	8747	9698	0.6%	9136	10778	0.3%	9007	10605	0.5%	8056	9676	0.4%	9287	11015	-0.3%	7884	8683
2023	0.1%	9352	10303	0.0%	8747	9698	0.6%	9201	10843	0.3%	9028	10648	0.5%	8100	9741	0.4%	9331	11059	0.1%	7819	8704
2024	0.1%	9374	10324	0.0%	8747	9698	0.7%	9266	10929	0.3%	9071	10691	0.5%	8143	9784	0.4%	9352	11123	0.1%	7819	8704
2025	0.1%	9374	10324	0.0%	8747	9698	0.7%	9331	10994	0.5%	9115	10756	0.5%	8186	9827	0.4%	9395	11167	0.1%	7840	8726
2026	0.1%	9395	10324	0.0%	8747	9698	0.7%	9395	11080	0.5%	9179	10821	0.8%	8251	9914	0.4%	9439	11210	0.1%	7840	8726

PUC 1-3

Request:

Please continue Table S-2 (Bates 41) through the end of the battery storage project or when the deferral benefits end, whichever is later.

Response:

Please see the table below.

Table S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$668.5**	**$160.3**	**$137.5**	**$218.9**	**$204.6**	**$5,896.4**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$497.6	$0.0	$0.0	$0.0	$0.0	$3,779.4
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$11.3	$0.0	$0.0	$0.0	$0.0	$713.3
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.4	$0.0	$0.0	$0.0	$0.0	$29.0
Energy Storage Reduction Benefits[9]	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$18.4	$18.4	$18.4	$18.4	$73.7
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$141.9	$119.0	$200.4	$186.2	$1,300.9
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$1,122.6**	**$109.5**	**$109.5**	**$109.5**	**$109.5**	**$4,576.3**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$804.0	$0.0	$0.0	$0.0	$0.0	$2,186.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$318.6	$109.5	$109.5	$109.5	$109.5	$2,389.5
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**0.60**	**1.46**	**1.26**	**2.00**	**1.87**	**1.29**

Notes:

(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.

(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.

(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.

(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers reflect year end projections.

(9) The Energy Storage Reduction benefits for 2018-2021 were calculated in the 2018 SRP Report as a NPV with a 4 year measure life. For the purposes of this illustration, their annual values are shown here as a simple division of the total by the four years.

Prepared by or under the supervision of: Lindsay Foley

PUC 1-4

Request:

What would be the cost of energy efficiency needed "to provide an estimated four years of additional deferral of the substation upgrade?" (Bates 15). Please provide your answer in Table S-2 (Bates 41) as extended in above data request.

Response:

The Company has not examined the cost of energy efficiency needed to provide an estimated four years of additional deferral to the substation upgrade. This would require an analysis of which types of energy efficiency measures and marketing tactics would be proposed, as well as the costs associated with that portfolio. As a guideline, the average cost per kW of the focused energy efficiency in the Tiverton NWA (DemandLink) Pilot (inclusive of the additional SRP marketing budget) was approximately $18,040. It has been the Company's experience that, over time, the cost per kW has steadily increased because it has been so heavily targeted with marketing and energy efficiency incentives for the past six years. The Company believes that more expensive measures and additional marketing above and beyond what was done in 2017 would be needed, increasing the cost per kW value provided above.

Prepared by or under the supervision of: Lindsay Foley

PUC 1-5

Request:

Please calculate the following: add the cumulative deferral benefits in Table S-2 (Bates 41) and the projected total benefits in the proposed 2018 SRP (Bates 27), divide this amount by the sum of cumulative system reliability procurement costs of the pilot ($1.9 million) plus the total projected costs of the battery storage project (Bates 27). Is this the appropriate benefit-cost ratio for the proposed battery storage project? Why or why not?

Response:

	$000s
Cumulative Deferral Benefits (Bates 41)	$653.3
2018 SRP Projected Total Benefits (Bates 27)	$721.3
Total	**$1,374.6**
Tiverton Pilot SRP Costs (Bates 41)	$1,951.5
Little Compton Battery Storage Costs (Bates 27)	$438.0
Total	$2,389.5
BC Ratio	**0.58**

This is not the appropriate benefit-cost ratio for the proposed battery storage project. Because of the delay in installing the battery storage project in 2017 as the Company originally intended, the Company evaluated whether the effort on its own could provide cost-effective benefits to this distribution need with a 2018 installation. This included a refresh of the load forecast and the distribution deferral benefit calculations. The proposal included in the 2018 SRP Report reflects the results of that evaluation and shows that it is a cost-effective effort to defer the Tiverton substation upgrade from 2018 through 2021, not 2012 through 2021.

Additionally, the above calculation excludes the additional benefits in the Total Resource Cost test. If it were appropriate to include consideration of the years 2012-2017 in the calculation of the benefit cost ratio of the Company's battery storage project proposal, a more accurate calculation would be the one shown in the expanded version of Table S-2 from the Company's response to PUC 1-3. In that analysis, the benefits of the years 2012-2017 are calculated using the Total Resource Cost test, and the benefits of the years 2018-2021 are calculated using the RI Test.

Prepared by or under the supervision of: Lindsay Foley

PUC 1-6

Request:

Referring to Table 9 (Bates 27) please recommend outcome-based metrics that hold the Company accountable to achieving the potential benefits of these actions.

Response:

The metrics proposed in the 2018 SRP Report will hold the Company accountable for achieving the potential benefits and are based on the completion of those efforts within the stated timeframe. The incentives associated with these metrics would be assessed as part of the development of the 2019 SRP Report and would be included in that funding request.

The initial version of the Distribution System Loading Map will be available by June 30, 2018, and will show the Company's distribution system summer loading to facilitate the location of Distributed Energy Resources (DER) and beneficial electrification facilities. The availability of the map by June 30, 2018 is the outcome metric that would enable the Company to achieve the incentive described in Table 9 (Bates 27).

The initial version of the DG-Focused Map will also be available by June 30, 2018 and will include a list of substations that are DG-ready (those that have had a transmission voltage side ground fault detection system installed). Additionally, a timeline for adding hosting capacity will be available by September 30, 2018. Availability of the DG map by June 30, 2018 is the outcome metric that achieves the incentive described in Table 9 (Bates 27).

By August 31, 2018, the Company and the Parties will engage in a stakeholder review process to determine a set of location-based avoided costs with documented next steps. By May 31, 2018, the Company will share with the Parties a marketing and engagement plan to promote the Distributed System Loading Map, the DG-Focused map, and other state or Company programs such as the Renewable Energy Growth Program and ConnectedSolutions. The Company will deploy the plan by May 31, 2018. Deployment of the marketing and engagement plan by May 31, 2018 is the outcome metric that achieves the incentive described in Table 9 (Bates 27).

Finally, the requests for proposals will be issued by December 31, 2018. The information in these RFPs will be developed using the information provided from the system data portal resources. Issuance of the RFPs by December 31, 2018 is the outcome metric that achieves the incentive described in Table 9 (Bates 27).

Prepared by or under the supervision of: Timothy Roughan

PUC 1-7

Request:

In Table 10 (Bates 29) please expand the heat map budget to breakdown items described at Bates 8.

a. Add a column showing quantifiable benefits and a description of those benefits.
b. Add a column describing qualitative benefits.

Response:

The data portal budget breakdown including the heat map is as follows.

Item	**Full Time Equivalent**	**Labor Cost with Overheads**	**Material / Software**	**Total**
Distribution Planning - Engineer	15%	$35,000		**$35,000**
Asset Data & Analytics - Analyst	15%	$35,000	$10,000	**$45,000**
Total		**$70,000**	**$10,000**	**$80,000**

The estimate was developed as an overall data portal effort. It was not itemized using the items described at Bates 8.

Currently, the benefits of a heat map cannot be quantified. The purpose of the heat map is to provide guidance to external parties as to where Distributed Energy Resource (DER) interconnections may be most beneficial to the system (for instance to address potential loading concerns). However, it is unknown how or to what extent the external parties will use the data portal. For this reason, National Grid believes the scope and low cost proposal is appropriate. Qualitatively, the data portal benefits include:

- Greater system benefits from DER providers and lower interconnection costs for DER providers. Using the data portal to target DER where they provide the most system benefits could help the utility manage the system in a more efficient manner. This would require a relationship between the DER provider and the utility on performance, controllability, or dispatch ability. Similarly, data portal maps may be used by DER providers to determine a location that lowers interconnection costs.

- Indefinite deferral of load relief related investment. With continued low growth rates, the successful deployment of cost-effective DER would reduce the load relief component of any system plan. Over time, this would result in less infrastructure investment.

PUC 1-7, page 2

- Preemptive deployment of DER allows the utility to manage system risks appropriately. National Grid can observe DER performance, controllability, and dispatch ability before system risks become severe.

Prepared by or under the supervision of: Ryan Constable

PUC 1-8

Request:

Referring to Table 9 (Bates 27), what identified needs are these RFPs addressing?

Response:

The RFPs in Table 9 (Bates 27) refer to the RFPs described on Bates page 9 of the 2018 System Reliability Procurement Report. Specifically, on Bates page 9, the Company stated: "The Company will also issue, by December 31, 2018, at least two new requests for proposals (RFPs) from third-party developers for the purchase of a set of NWA resources. The decision on where to locate the NWAs will be based on the information provided in the Portal, as well as the Northwest Rhode Island study."

Consequently, throughout 2018, the Company will be working to identify specific needs and issue RFPs, as needed.

Prepared by or under the supervision of: Ryan Constable

PUC 1-9

Request:

Has the Company developed a similar web portal and/or maps in any of its jurisdictions?

a. If so, please describe any regulatory decisions regarding cost recovery and incentives for the development and deployment of web portals and maps.

b. In addition, please describe any additional revenue streams generated by the Company from the web portal and maps.

c. Has the Company considered ways to generate revenue from the web portal and maps? If so, please describe those ideas and deliberations.

Response:

In New York, the Company's affiliate has undertaken significant efforts to gather various system data and create system maps to present that information in a useful format.

a. In support of regulatory requirements stemming from the Reforming the Energy Vision (REV) proceeding in New York, utilities are required to provide access to various system data to facilitate the integration of Distributed Energy Resources (DER). As part of its Distributed System Implementation Plan (DSIP), the Company's affiliate in New York developed the System Data Portal to present the wide array of data requested in a common location and format. The System Data Portal continues to evolve as new data (such as hosting capacity analysis) becomes available. Costs to develop, populate, and maintain the portal, including any additional resources required to perform new analysis in the generation of new data sets to be evaluated, are included in the traditional cost of service calculation and presented in the recent general New York rate case for recovery.

b. To date, there are no new revenue streams associated with the System Data Portal in New York. As part of REV, if certain data sets are determined to be "value added data", there may be opportunities to generate future Platform Service Revenues for the utility.

c. The Joint Utilities of New York coordinate a stakeholder engagement working group regarding system data, and the topic of value added data is being discussed but has yet to define any specific revenue opportunities.

Prepared by or under the supervision of: Ryan Constable

PUC 1-10

Request:

Has the Company proposed specific metrics for peak demand reduction and/or improved load factor in regulatory proceedings in any of its other jurisdictions? If so, please describe the proposed metrics.

Response:

The Company's affiliate, Niagara Mohawk, initially proposed a Peak Reduction and Load Factor metric in its rate case that was filed on April 28, 2017 in response to the Reforming the Energy Vision (REV) Track Two Order. However, the New York Department of Public Service Staff recommended the removal of the Load Factor metric, and the Company agreed to remove the Load Factor metric. The Company's proposed Peak Reduction metric would measure the weather-normalized non-coincident peak in the Niagara Mohawk service territory. Please see below for the targets and basis point incentive levels proposed in the Company's rebuttal testimony filed with the NYPSC on September 15, 2017, and see Attachment 1 for the target calculations.

Peak Reduction	**Basis Points**					**Targets (MW)**			
	2017	**2018**	**2019**	**2020**		**2017**	**2018**	**2019**	**2020**
Minimum	5	5	5	5		6,686	6,688	6,675	6,647
Target	10	10	10	10		6,609	6,571	6,510	6,443
Maximum	20	20	20	20		6,499	6,433	6,345	6,251

Prepared by or under the supervision of: Lindsay Foley

NMPC Peak Reduction Targets

MINIMUM PEAK REDUCTION TARGETS					
Year	(1)	2017	2018	2019	2020
Forecast Peak Load	(2)	6886	6960	7024	7068
Minimum DER Targets	(3)=(4)+(5)+(6)+(7)+(8)+(9)	200	272	349	421
Solar PV	(4)	14	33	51	65
Demand Response	(5)	140	145	150	155
Energy Efficiecy	(6)	44	91	142	193
VVO	(7)	0	0	1	2
Storage	(8)	0	0	0	0
CHP	(9)	1	3	4	6
Minimum Peak Load	**(10)=(2)-(3)**	**6686**	**6688**	**6675**	**6647**

MID-POINT PEAK REDUCTION TARGETS					
Year	(1)	2017	2018	2019	2020
Forecast Peak Load	(2)	6886	6960	7024	7068
Midpoint DER Targets	(3)=(4)+(5)+(6)+(7)+(8)+(9)	277	389	514	625
Solar PV	(4)	22	58	98	127
Demand Response	(5)	200	210	220	230
Energy Efficiecy	(6)	51	114	181	248
VVO	(7)	0	0	2	4
Storage	(8)	2	2	6	8
CHP	(9)	2	4	7	9
Midpoint Peak Load	**(10)=(2)-(3)**	**6609**	**6571**	**6510**	**6443**

MAXIMUM PEAK REDUCTION TARGETS					
Year	(1)	2017	2018	2019	2020
Forecast Corrected Peak Load	(2)	6886	6960	7024	7068
Maximum DER Targets	(3)=(4)+(5)+(6)+(7)+(8)+(9)	386	526	679	817
Solar PV	(4)	25	70	120	157
Demand Response	(5)	300	315	330	345
Energy Efficiecy	(6)	57	131	210	289
VVO	(7)	0	0	2	4
Storage	(8)	2	5	8	10
CHP	(9)	3	6	9	12
Maximum Peak Load	**(10)=(2)-(3)**	**6499**	**6433**	**6345**	**6251**

PUC 1-11

Request:

Please explain why the Company proposed the battery storage project as a new pilot when the battery was originally intended to be part of the DemandLink pilot and deployed in Summer 2017 (Bates 17, 19, and 25).

Response:

The Company proposed the Little Compton Battery Storage Project (Project) as a new effort separate from the DemandLink pilot (Pilot) because the original Pilot was intended to run only through 2017. The original pilot used an older, now outdated, benefit-cost model and had already provided many lessons learned. One lesson learned is that pursuing further customer-side load relief opportunities was highly unlikely to provide the needed peak reductions in electric use. Rather than proposing to extend the Pilot, given the delay in the Project's original implementation plan, the Company is proposing to expand the Project's timeline from one year of reduction to four years. This will increase the amount of cost effective peak reduction provided to the area and, as currently forecasted, delay the need for a substation upgrade until 2021 instead of just 2018. Therefore, the Company believes that the Project is more appropriate when proposed and evaluated on its own.

Prepared by or under the supervision of: Lindsay Foley

PUC 1-12

Request:

Please compare the DemandLink demand response pilot to the Company's Connected Solutions program. Have lessons learned from the DemandLink pilot been applied to the Connected Solutions program and vice versa?

Response:

Please see the table below for a comparison between the DemandLink Pilot and the ConnectedSolutions program.

Item	**DemandLink Pilot**	**ConnectedSolutions RI Program**
Purpose of the Pilot/Program	Reduce the local substation peak to defer a new feeder at Tiverton Substation	Reduce the statewide peak to defer distribution, transmission, and capacity costs statewide
Customer-owner equipment being used	Ecobee thermostats	Nest, Honeywell, and Ecobee thermostats
Number of customers in the Pilot/Program	~200	~1,200
Targeted area	Specific feeders covering most of Tiverton and all of Little Compton	Statewide
Customer incentive amount	$40 per customer per year for 100% of event participation	For Ecobee and Honeywell: $25 per customer per year for at least 75% of event participation For Nest: $40 per customer per year the first year, then$25 for the second year onwards every year the customer remains in the program
How customers are notified	Email	Email, In-App notifications (for Nest customers)
Event Triggers	Tiverton area weather forecast and local feeder forecasts	When the statewide load is forecasted to reach its annual peak
Pilot/Program parameters	No precooling, 2 degree Fahrenheit setback	Precooling enabled (for Honeywell and Nest), 3 degree Fahrenheit setback

Lessons learned from the DemandLink Pilot have been applied to the ConnectedSolutions program. Lessons learned from the ConnectedSolutions program have not been applied to the DemandLink Pilot. This is because ConnectedSolutions began in the summer of 2016, and evaluated results were not available in time to be formally incorporated into the DemandLink Pilot.

PUC 1-13

Request:

What was the date and time of the highest demand in the pilot area occur in 2016?

Response:

The peak load for the 33F3 circuit was 8.42 MVA in 2016. This occurred on 8/14 at 5:30 PM.

The peak load for the 33F4 circuit was 10.0 MVA in 2016. This occurred on 8/14 at 6:00 PM.

Prepared by or under the supervision of: Ryan Constable

PUC 1-14

Request:

Regarding the actual battery facility itself, as proposed:

a. What distribution system and regional tariffs will apply to the battery facility?
b. In what markets, if any, and if known, will the battery facility participate?
c. What customer class will the battery facility belong to?
d. Who will bear the cost of service (for example, energy, distribution, transmission, program charges, etc.) and interconnection of the facility?
e. Is the battery facility intended to be used for System Reliability Procurement for certain summer months (or certain hours)? If so, please provide, if known, how the battery will be operated in the remainder of the year?
f. Can the battery facility be repurposed for future projects? For example, is the battery facility installation mobile?
g. Is the contract for the battery facility service terminable or extendable? If so, what are the applicable conditions and consequences?
h. What is intended to happen to the battery at the conclusion of the pilot? For example, is the battery decommissioned and removed from the system?
i. Would the cost of the eventual system upgrade in the pilot area (for example, the cost of adding an additional feeder) in any way be different depending on whether or not the battery facility remains in place after the end of the storage pilot?

Response:

a. Since the proposed project is sized at greater than 200 kWs, it will be take electric delivery service from the Company at the G-32 rate. The customer has not indicated whether they plan to be a default supply customer or whether they plan to take third-party service from a supplier. For regional tariffs, see the Company's response in section (b) below.

b. Outside of cycling for the System Reliability Procurement (SRP) hours set forth in the System Reliability Services Contract, the battery facility has indicated plans to participate in ISO-NE's ancillary services markets, primarily as an Alternative Technology Regulation Resource (ATRR).

c. The customer class will be the Company's Large Demand Rate G-32.

d. The vendor will bear the cost of service and the cost to interconnect the facility.

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e. Yes. As outlined in the 2018 SRP Plan, the battery would be used to provide load relief during the months of June through September and during the hours of 3:30 to 7:30 p.m. Outside of cycling for the SRP hours set forth in the System Reliability Services Contract, the battery facility plans to participate in ISO-NE's ancillary services markets, primarily as an Alternative Technology Regulation Resource (ATRR).

f. The vendor has indicated the battery facility can be repurposed for future projects. Unlike a solar array, the capacity is compact, skid mounted, and can be transported and re-energized at a different location, provided an adequate pad site and interconnection facilities exist.

g. The proposed contract is extendable up to 10 years, but may not be terminated (except for casualty or default) within the initial contract period, which is still to be determined.

h. National Grid and the vendor hope that at the end of the pilot period, the measure will continue to be a cost-effective means of addressing local peak concerns in the Tiverton and Little Compton area relative to system upgrade and that there may be an approval from the PUC to allow National Grid to offer a contract extension as provided for in the contract. If the contract is not extended, the vendor has indicated that it plan to continue to bid the battery's capacity into the ISO-NE forward capacity market, staking capacity market revenue with revenue from participation in ISO-NE's ancillary services markets.

i. No. The costs would not be changed if the battery system remains in place. The battery system is not large enough to permanently offset the substation upgrades.

Prepared by or under the supervision of: Lindsay Foley