The Narragansett Electric Co. d/b/a National Grid's Proposed Power Sector Transformation (PST) Vision and Implementation Plan

Docket 4780

Request for Information

Requesting Party:	New Energy Rhode Island (NERI)
To:	National Grid
Request No.:	NERI-4
Date of Request:	February 27, 2018
Response Due Date:	March 20, 2018
Subject/Panel:	Performance Incentives (Book 1, Chapter 9; Technical Conference on 01/31/18; Pre-filed testimony; Work Papers)

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1. For each performance incentive the Company proposes, please describe:
    a. How baseline conditions were calculated:
        i. What data did the Company use?
        ii. How many years of data did the Company use?
        iii. Which categories of costs do baseline assumptions reflect?
    b. How the proposed incentive levels were designed.
    c. The net cost (*i.e.*, the costs of paying incentives) versus benefits (*i.e.*, reductions in revenue requirements and operating costs) for each incentive category?

    Response can be found on Bates page(s) 1-2.

2. For each performance incentive the Company proposes, please describe how the Company addressed temporal mismatches in the proposed incentives. In other words, do changes in the Company's practices and operations in response to the incentives result in ratepayer revenue requirements savings on a contemporaneous basis with the cost of incentive payments? What consideration or adjustments did the Company make, or does the Company propose, to address these issues?

    Response can be found on Bates page(s) 3.

3. For each performance incentive the Company proposes, please describe:
    a. What inter-class and intra-class issues the Company considered in the proposals.
    b. How the Company addressed, or proposes to address, these issues.
    c. To what extent demand-related savings accrue to customers that cause demand reductions.
    d. How are the benefits created by the incentives tracked against cost of service elements in the development and updating of cost of service study and revenue

requirements?

Response can be found on Bates page(s) 4-5.

4. For each performance incentive the Company proposes, please describe the ultimate consumption, usage, bill, revenue requirement, or other outcomes that the incentive was designed to achieve.

   Response can be found on Bates page(s) 6-7.

5. For proposed incentives that do not include outcome-based metrics (and instead, for example, uses metrics with number of dollar spent, or systems installed), please explain why those incentives do not include outcome-based metrics.

   Response can be found on Bates page(s) 8.

6. Reference Chapter 9, p.8. How does the Company account for the risk of double-incentivizing single outcomes? For example, reducing peak demand can also reduce carbon emissions.

   Response can be found on Bates page(s) 9-11.

7. How does the Company match savings causers with program costs? For example, volt-var optimization, increased capacity for distributed generation, and demand-response will all contribute to peak reduction; even if baseline forecasts of other incentive programs have been included in peak reduction targets, how will the Company prevent a PBI that over-performs its baseline from also being counted toward peak reduction?

   Response can be found on Bates page(s) 12.

8. Reference the Company's statement in Chapter 9, p. 8, that it "expects a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts such as the deployment of volt-var optimization (VVO), and demand response to contribute to meeting these peak demand reduction targets." The Company also states that forecasts for these other incentivized programs are included in the peak forecasts. How were those forecasts determined, and are they below the maximum target for each program? Will above-forecast levels of attainment of incentivized programs be double-counted by peak reduction incentives?

   Response can be found on Bates page(s) 13.

9. The Company proposes positive-only incentives in order to test the efficacy of performance-based programs. Please explain the Company's position about when incentives should be positive-only, or asymmetrical, and when they should be designed to be symmetrical, that is, containing both positive incentives and penalties.

   Response can be found on Bates page(s) 14.

10. Has the Company's experience in other jurisdictions and in the gas utility business informed its incentive proposals? If yes, please describe that experience.

    Response can be found on Bates page(s) 15.

11. For the Capital Efficiency Incentive, did the Company consider the risk that, as designed, it could have the effect of incentivizing over-budgeting in project planning?

    Response can be found on Bates page(s) 16-21.

12. Did the Company evaluate the impact of the proposed incentives on the Company's overall risk profile as relates to earning and exceeding revenue requirements? If yes, what were the results of the evaluation?

    Response can be found on Bates page(s) 22.

13. Did the Company evaluate any other efforts and/or outcomes for developing additional incentives? If yes, please describe those additional efforts and/or outcomes, and why they were not proposed as PBIs.

    Response can be found on Bates page(s) 23.

14. Has the Company evaluated the value of "scorecard metrics" to begin tracking data on behaviors and outcomes that may not yet be ready for treatment with earnings incentives?

    Response can be found on Bates page(s) 24.

15. For each performance incentive the Company proposes, please provide a list and description of the specific data and metrics that the Company will track and report.

    Response can be found on Bates page(s) 25-29.

16. Did the Company consider developing a PBI to incentivize avoiding capital projects in the ISR, rather than reducing the cost of projects already proposed? Did the Company also consider a PBI for avoiding distribution line projects and maintenance, instead of an incentive for reducing cost-per-mile of completed projects?

    Response can be found on Bates page(s) 30.

17. Reference Chapter 4, p. 9. How did the Company determine that the cap on retained savings should be $2.5 million on expected yearly budgets of $5-$15 million? Does the Company have reason to believe it is overspending by 30% or more on Complex Capital Projects?

    Response can be found on Bates page(s) 31-32.

18. Why are PBIs necessary for programs or policies currently underway or pending Commission approval? In particular, please reference the existing/pending programs described on Chapter 9, p. 14, regarding the incentive for the delivery of the VVO pilot, and Chapter 9, p. 10, regarding the DG substations incentive for the 3V0 program already submitted in an ISR filing. What incremental or additive actions by the Company will ratepayers be incentivizing through the PBIs proposed in the PST plan?

    Response can be found on Bates page(s) 33-34.

19. Reference Chapter 4, p. 10-11, regarding the DG-Friendly Substation Transformer.

    a. Please describe what actions by the Company will be incentivized by the DG-Friendly Substation Transformer PBI that are not incented by the suite of Interconnection PBIs or current Company practice.

    b. Did the Company consider an outcome-based metric, such as the amount of increased DG installed by customers resulting from the work, rather than the amount of work completed by the Company?

    Response can be found on Bates page(s) 35.

20. Reference the Company's statement in Chapter 4, p. 20, that "The Company has proposed

the largest incentive around the DG-Friendly Substation metric. The Company's proactive installation of 3V0 has the potential to expedite interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits described above. However, the Company has not quantified the net benefits to customers from these efforts, due to the assumptions that would have to be made about the timing of distributed generation installations absent these investments, the number and size of installations accelerated, and the specific technology being installed." Please explain why the DG-Friendly Substation Transformer metric is allocated a large number of potential basis points if the customer benefit has not been calculated.

Response can be found on Bates page(s) 36.

21. For performance incentive programs that do not currently have set targets, how did the Company allocate basis points?

    Response can be found on Bates page(s) 37.

22. For each performance incentive the Company proposes, how did it calculate basis points in proportion to customer savings?

    Response can be found on Bates page(s) 38.

23. Reference Chapter 9, p. 13, regarding Behind-the-Meter Storage. Please describe:

    a. What action will the Company be incentivized to perform with regard to behind the meter storage?

    b. What metrics will the Company use to track and evaluate the program?

    c. Does the Company have any current or potential programs for promoting behind-the-meter storage independent of this PBI?

    Response can be found on Bates page(s) 39.

24. Reference Chapter 9, p. 12, regarding the Electric Heat Initiative. Will the Company's natural gas customers be eligible and targeted for beneficial heat electrification?

    Response can be found on Bates page(s) 40.

25. Please provide the program costs associated with the Electric Heat and Electric Vehicle Initiatives. Please confirm that those costs are incorporated in the Company's revenue requirement.

    Response can be found on Bates page(s) 41.

26. Reference Chapter 4, p. 16, regarding the Interconnection Support – Estimate versus Actual Cost. Please describe how the Company will develop the "sum of costs estimated by the Company for interconnection."

    Response can be found on Bates page(s) 42.

27. Has the Company accounted or controlled for the possibility that the DG-Friendly Substation Program and the suite of Interconnection incentives may result in double-incenting the same outcomes (*e.g.*, decreased costs and time required for interconnection)?

    Response can be found on Bates page(s) 43.

NERI 4-1

Request:

For each performance incentive the Company proposes, please describe:

a. How baseline conditions were calculated:

   i. What data did the Company use?

   ii. How many years of data did the Company use?

   iii. Which categories of costs do baseline assumptions reflect?

b. How the proposed incentive levels were designed.

c. The net cost *(i.e.,* the costs of paying incentives) versus benefits *(i.e.,* reductions in revenue requirements and operating costs) for each incentive category?

Response:

a. Only two of the Company's proposed performance incentive mechanisms, Monthly Transmission Peak Demand Reduction and Forward Capacity Market Peak Demand Reduction, compare Company performance against a historic baseline. For 2019, both peak reduction targets are denoted in terms of reductions relative to 2018. For the purposes of target setting, the Company set targets using its peak demand forecast for the years 2018 through 2021, adjusting for the impacts of efficiency, solar PV, VVO, energy storage, and the proposed Electric Heat Initiative as discussed in the Company's responses to NERI 4-7 and NERI 4-8. With respect to part a.iii, the Company has not developed cost-based baselines as they were not necessary to support the development of the proposed performance incentive mechanisms.

b. Please see the Company's response to NERI 4-22. For additional discussion of the basis points proposed for each performance incentive mechanism, please see the Company's responses to Division 3-9 through Division 3-23 (Responses to the Division's Third Set of Data Requests, Bates Pages 73-139).

c. Where possible, the Company has provided a quantitative comparison of the benefits driven by the incentive and the costs of providing the incentive. Please see Schedule PST-1, Chapter 9 – Performance (Bates Pages 177-182 of PST Book 1). For many of the proposed incentives, it is not possible to quantify some or all of the expected benefits. With respect to the cost of paying incentives, the table below provides a summary of the maximum incentive payment to the Company for 2019, if all maximum targets are achieved. The assumed basis point value is as described in Schedule PST-1, Chapter 9 – Performance (Bates Page 167 footnote 6 of PST Book 1).

Category and Supporting Metrics	Max Basis Points	Max Value in 2019
System Efficiency	**23.5**	**$ 1,398,086**
Monthly Transmission Peak Demand Reduction	3	$ 178,479
Forward Capacity Market Peak Demand Reduction	18	$ 1,070,874
EV Off-Peak Charging Rebate Participation	2.5	$ 148,733
Distributed Energy Resources	**29.5**	**$ 1,755,044**
DG-Friendly Substation Transformers	10	$ 594,930
DR -- Connected Solutions Participation	5	$ 297,465
DR -- C&I Participation	5	$ 297,465
Electric Heat Initiative	2	$ 118,986
Electric Vehicles	3.5	$ 208,226
Behind-the-Meter Storage	2	$ 118,986
Utility-Owned Storage	2	$ 118,986
Network Support Services	**22**	**$ 1,308,846**
VVO Pilot Impacts	2	$ 118,986
AMF Customer Engagement and Deployment	2	$ 118,986
Interconnection -- Time to ISA	6	$ 356,958
Interconnection -- Avg days to system modification	6	$ 356,958
Interconnection -- Estimated vs actual costs	6	$ 356,958
Total	**75**	**$ 4,461,975**

(This response is identical to the Company's response to NERI 21-1 in Docket No. 4770)

NERI 4-2

Request:

For each performance incentive the Company proposes, please describe how the Company addressed temporal mismatches in the proposed incentives. In other words, do changes in the Company's practices and operations in response to the incentives result in ratepayer revenue requirements savings on a contemporaneous basis with the cost of incentive payments? What consideration or adjustments did the Company make, or does the Company propose, to address these issues?

Response:

There is no "temporal mismatch" associated with the proposed performance incentive mechanisms. All performance incentive payments that will be made through the Power Sector Transformation (PST) factors are based on Company performance for the prior calendar year. To the extent that a Company activity in a given calendar year leads to benefits in a future calendar year, those benefits have been discounted in the Company's assessment of costs and benefits.

The savings or benefits created by incentives will not impact the Company's current cost of service studies and revenue requirements. However, incentives that lead to customer savings will be passed through via the appropriate mechanisms. Customer savings achieved through the Forward Capacity Peak Demand Reduction incentive will be passed through to customers in Standard Offer Service Rates that are lower than they otherwise would have been. Similarly, savings on billed transmission due to peak demand reductions will be passed on to customers via a Transmission Service Cost Adjustment that is lower than it otherwise would have been. Note that many of the benefits of the performance incentive mechanisms are societal in nature (e.g., CO_2 reductions) and would accrue broadly across all customers, but not reduce utility costs.

(This response is identical to the Company's response to NERI 21-2 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-3

Request:

For each performance incentive the Company proposes, please describe:

a. What inter-class and intra-class issues the Company considered in the proposals.

b. How the Company addressed, or proposes to address, these issues.

c. To what extent demand-related savings accrue to customers that cause demand reductions.

d. How are the benefits created by the incentives tracked against cost of service elements in the development and updating of cost of service study and revenue requirements?

Response:

a. The Company does not believe that the proposed performance incentives raise inter-class or intra-class issues that require further consideration at this time.

b. See the Company's response to part a., above.

c. The extent to which individual customers capture immediate savings from coincident peak demand reductions that will support peak demand reduction targets will (as is currently the case) depend upon their rate structure and supplier (i.e., whether they are a standard offer service customer or have a competitive supplier). For example, under the current rate design, residential customers on Standard Offer Service will not see an immediate savings from their individual demand reductions. However, industrial and commercial customers on demand-based rates will accrue savings from their individual coincident peak demand reductions in the event that those reductions coincide with their own peak demands. Customers with competitive suppliers making coincident peak demand reductions will see savings via a lower installed capacity (ICAP) tag.

   Peak demand reductions that, in the aggregate, lead to Forward Capacity Market savings will be passed through to customers in Standard Offer Service rates that are lower than they otherwise would have been. Similarly, savings on billed transmission due to peak demand reductions will be passed on to customers via a Transmission Service Cost Adjustment that is lower than it otherwise would have been.

   The Company expects all customers to benefit over time from forward capacity market and billed transmission savings; however, because it is not possible to determine how peak reduction contributions will be spread within and among customer classes, it is not possible to indicate the extent to which individual customers or classes might subsidize others through their peak demand reductions. Nonetheless, the Company has no reason to believe that there will be undue cross subsidization.

d. The benefits created by incentives will not impact the Company's current cost of service studies and revenue requirements. The Company expects to demonstrate benefits and savings from incentives when it reports on its performance against incentive targets in the annual PST reconciliation filing, if approved by the Public Utilities Commission. Many of the benefits of the performance incentive mechanisms are societal in nature (e.g., CO_2 reductions) and would accrue broadly across all customers, but not reduce utility costs.

(This response is identical to the Company's response to NERI 21-3 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-4

Request:

For each performance incentive the Company proposes, please describe the ultimate consumption, usage, bill, revenue requirement, or other outcomes that the incentive was designed to achieve.

Response:

The ultimate objectives for each performance incentive mechanism are provided below.

- Monthly Transmission Peak Demand Reduction: Reduce monthly transmission billings from New England Power to Narragansett Electric relative to what they otherwise would have been.

- Forward Capacity Market Peak Demand Reduction: Reduce forward capacity market costs relative to what they otherwise would have been.

- EV Residential Off-Peak Charging Rebate: Encourage customer engagement in a program featuring time-varying price signals to inform a broader transition to time-varying rates; support Rhode Island's Zero Emission Vehicle (ZEV) and greenhouse gas (GHG) goals; and encourage efficient integration of new load to avoid incremental system costs.

- DG Friendly Substation Transformer: Accelerate the benefits from DG in support of the state's renewable energy and greenhouse gas goals. Benefits include:

    - Reductions in CO_2 and criteria pollutant emissions
    - Avoided energy and capacity costs
    - Avoided renewable energy credit costs

- Demand Response - Connected Solutions Participation: Encourage customer engagement in support of the Power Sector Transformation (PST) goals of giving customers more energy choices and information.

- Demand Response - C&I Participation: Encourage customer engagement in support of the PST goals of giving customers more energy choices and information.

- Electric Heat: Reduce CO_2 through the conversion of oil heat customers.

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- Electric Vehicles: Support the state's greenhouse gas and ZEV goals by increasing the number of electric vehicles in Rhode Island.

- Behind the meter storage: Integrate cost-effective storage in support of attainment of potential system benefits and customer savings, and support the state's renewable energy and GHG goals.

- Company-Owned Storage: Integrate cost-effective storage in support of attainment of potential system benefits and support the state's renewable energy and greenhouse gas goals.

- AMF customer engagement: Expedite the achievement of system and customer benefits from AMF.

- VVO Pilot Delivery: Ensure the VVO/AMF pilot proposed in the Infrastructure, Safety, and Reliability Plan provides maximizes benefits to the system and supports maximization of system benefits under broader AMF deployment.

- Interconnection Support – Time to ISA: Support, timely and efficient interconnection of distributed generation to maximize the benefits from distributed generation.

- Interconnection Support – Average Days to System Modification: Support timely and efficient interconnection of distributed generation to maximize the benefits from distributed generation.

- Interconnection Support – Estimate versus Actual Costs: Support timely and efficient interconnection of distributed generation to maximize the benefits from distributed generation.

(This response is identical to the Company's response to NERI 21-4 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-5

Request:

For proposed incentives that do not include outcome-based metrics (and instead, for example, uses metrics with number of dollar spent, or systems installed), please explain why those incentives do not include outcome-based metrics.

Response:

Two of the Company's proposed performance incentive mechanisms may fall into the category described in the question: DG-Friendly Substation Transformers and Advanced Meter Functionality (AMF) Customer Engagement and Deployment. With respect to DG-Friendly Substations, this metric is intended to support achievement of Rhode Island's clean energy and CO_2 reduction goals by enabling accelerated interconnection of distributed generation. However, the Company focused the metric on installation of 3V0 because it is more clearly connected to Company activities and influence than alternative metrics that might be more outcome-focused. It would be challenging for the Company to demonstrate, for example, that the Company's 3V0 program resulted in additional MW of DG that would otherwise not have come online, or that it shifted the installation of these MW forward in time by some number of months. Development of supporting counterfactuals would likely be complex and contentious.

With respect to AMF Customer Engagement and Deployment, the Company has structured this metric in terms of customer outreach and deployment milestones because the incentive is intended to support the Company's ability to deliver the benefits of AMF to Rhode Island customers as expeditiously as possible, and to maximize near-term benefits from deployment. However, the broader objectives of AMF deployment (namely, customer and system benefits) will not be observable until full deployment of AMF (and associated customer offerings) is complete. Therefore, a metric focused on that outcome is not feasible at this time.

(This response is identical to the Company's response to NERI 21-5 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-6

Request:

Reference Chapter 9, p.8. How does the Company account for the risk of double- incentivizing single outcomes? For example, reducing peak demand can also reduce carbon emissions.

Response:

Please see Attachment NERI 4-6, which is the Company's response to Division 3-25.

(This response is identical to the Company's response to NERI 21-6 in Docket No. 4770)

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Division 3-25

Request:

Please identify each instance where the achievement of one PIM target might also contribute to the achievement of another PIM target; i.e., where there is overlap among the PIMs.

Response:

Many of the performance incentive mechanisms will either directly or indirectly provide some support toward the achievement of the Forward Capacity Market Peak Demand Reduction and Monthly Transmission Peak Demand Reduction metrics. However, these performance incentive mechanisms are included in the Company's portfolio because they are geared toward the achievement of either additional or separate policy goals, and, therefore, provide other distinct benefits that justify their value. Conversely, multiple performance incentive mechanisms may support the same broad policy goal but also support independent objectives. The Company sought to propose a set of performance incentive mechanisms that is complementary but not redundant, and which will collectively provide incentives for the Company to effectively support achievement of state policy goals.

For example, achievement of the Off-Peak Charging Rebate Participation targets will result in a modest contribution toward the two peak reduction targets. However, that particular performance incentive mechanism is important in that it is focused on customer engagement, a priority in both Docket 4600 and Power Sector Transformation; and supportive of the State's ZEV and CO_2 near-term goals as it provides a timely means to reward off-peak charging by many electric vehicle drivers during the period before time-varying rates are implemented.

The Demand Response participation performance incentive mechanisms will similarly support the peak reduction metrics. As with the Off-Peak Charging Rebate, the Company emphasized the policy goal of customer engagement in developing these performance incentive mechanisms.

The two energy storage performance incentive mechanisms will also provide some support for peak reduction if targets are achieved. However, they link directly to the Power Sector Transformation goal of building a flexible distribution system to integrate more clean energy generation in support of the State's CO_2 reduction goals and Governor Raimondo's goal of 1000 MW of clean energy by 2020. The Behind the Meter Storage performance incentive mechanism also directly supports the Docket 4600 goal of fostering customer investment in their facilities.

The Electric Heat Initiative and Electric Vehicles performance incentive mechanisms provide direct support of the State's CO_2 reduction goals. The Electric Vehicles performance incentive mechanism provides support for the State's ZEV goals. The Electric Heat Initiative may provide a modest contribution to annual peak reduction that has been accounted for in setting the

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Forward Capacity Market Peak Demand Reduction targets. The Electric Heat Initiative also supports local economic development.

The DG-Friendly Substation Transformers and three Interconnection performance incentive mechanisms will all serve to expedite the interconnection of distributed generation. The DG-Friendly Substation Transformers performance incentive mechanism is a complement to the Interconnection performance incentive mechanisms, as completion of the system investments associated with the substation transformer targets will mean that customers can more readily benefit from expedited interconnection timelines. The three Interconnection performance incentive mechanisms each focus on different aspects of the interconnection process, such that their benefits will not be overlapping. All of these performance incentive mechanisms provide support for the State's clean energy and CO_2 goals, and will help to support economic development in the State of Rhode Island.

The Volt/VAR Optimization (VVO) Pilot Impacts performance incentive mechanism targets would imply a small contribution to the Forward Capacity Market and Monthly Transmission peak demand reduction targets. However, this performance incentive mechanism is intended to support outstanding delivery of the pilot, which will ultimately provide lessons that inform and ensure more efficient realization of benefits from broader AMF deployment and grid modernization efforts.

Because of the Company's proposed timeline for AMF deployment, the AMF Customer Engagement and Deployment performance incentive mechanisms targets are unlikely to impact the achievement of other performance incentive mechanisms.

(This response is identical to the Company's response to Division 10-25 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-7

Request:

How does the Company match savings causers with program costs? For example, volt-var optimization, increased capacity for distributed generation, and demand-response will all contribute to peak reduction; even if baseline forecasts of other incentive programs have been included in peak reduction targets, how will the Company prevent a PBI that over-performs its baseline from also being counted toward peak reduction?

Response:

With the exception of energy efficiency, any incentives applicable to other programs that contribute peak reductions are rewarded not for the peak reductions of those programs, but for other objectives or benefits advanced by those programs. Please see the Company's response to NERI-4-4, which discusses the objectives of each individual performance incentive. The Company recognizes that peak reductions from energy efficiency are eligible for existing energy efficiency incentives. The Company expects to demonstrate that MW reductions from efficiency do not benefit from both Power Sector Transformation and energy efficiency incentives.

(This response is identical to the Company's response to NERI 21-7 in Docket No. 4770)

NERI 4-8

Request:

Reference the Company's statement in Chapter 9, p. 8, that it "expects a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts such as the deployment of volt-var optimization (VVO), and demand response to contribute to meeting these peak demand reduction targets." The Company also states that forecasts for these other incentivized programs are included in the peak forecasts. How were those forecasts determined, and are they below the maximum target for each program? Will above-forecast levels of attainment of incentivized programs be double-counted by peak reduction incentives?

Response:

Please see the Company's response to part c. of Division 1-33 for discussion of the forecast for peak impacts of energy efficiency and distributed generation (solar PV). To assess the impacts of proposed Company projects on peak demand, the Company used the same estimates of peak impacts that were included in the project-specific benefit-cost analysis.

It is not clear what is meant by the reference to "maximum target for each program." With the exception of energy efficiency, the other Power Sector Transformation (PST) programs do not have an incentive for peak demand reduction and associated peak demand reduction targets. The Company has noted that it will demonstrate that annual peak MW reductions due to energy efficiency programs that are eligible for an incentive are not awarded an additional incentive. If the peak reduction impacts of the Company's proposed programs are greater than expected, those additional contributions would count toward the achievement of the Company's peak targets. This is desirable, because it will encourage the Company to implement those programs in a way that maximizes peak demand reductions, to the benefit of customers.

(This response is identical to the Company's response to NERI 21-8 in Docket No. 4770)

NERI 4-9

Request:

The Company proposes positive-only incentives in order to test the efficacy of performance-based programs. Please explain the Company's position about when incentives should be positive-only, or asymmetrical, and when they should be designed to be symmetrical, that is, containing both positive incentives and penalties.

Response:

Incentives designed to deliver new benefits and savings to customers (and in many cases reflect new areas of accountability for the Company that expand beyond its traditional core obligations) should be positive-only, at least in the near term. Symmetrical incentives may be appropriate in some instances for categories of performance associated with services that the Company has long-standing experience providing (e.g., safety and reliability services).

(This response is identical to the Company's response to NERI 21-9 in Docket No. 4770)

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NERI 4-10

Request:

Has the Company's experience in other jurisdictions and in the gas utility business informed its incentive proposals? If yes, please describe that experience.

Response:

The Company's incentive proposals have been informed by its experience developing Earnings Adjustment Mechanisms (EAMs) in New York during Niagara Mohawk Power Corporation's (Niagara Mohawk) 2017 electric and gas rate case. The Company's proposal draws upon the basic incentive and target structure used in the Niagara Mohawk EAMs, and the Company's approach to target setting, basis point allocation, and benefits sharing between customers and shareholders draws upon the approach developed in Niagara Mohawk proceedings. Although informed by National Grid's Niagara Mohawk experience, the Company's portfolio of proposed incentives in this proceeding has been carefully designed to be directly supportive Rhode Island's specific energy policy goals and to provide benefit to Rhode Island customers.

(This response is identical to the Company's response to NERI 21-10 in Docket No. 4770)

NERI 4-11

Request:

For the Capital Efficiency Incentive, did the Company consider the risk that, as designed, it could have the effect of incentivizing over-budgeting in project planning?

Response:

The Company interprets this question as referring to the Company's proposed Complex Capital Projects Capital Cost Incentive. Please see Attachment NERI 4-11, the Company's response to Division 3-6, part d., which responds to this question.

(This response is identical to the Company's response to NERI 21-11 in Docket No. 4770)

Division 3-6

Request:

Regarding the Complex Capital Projects Capital Cost Incentive:

a. Please provide a definition for "complex capital projects".

b. How will the Company determine whether a capital project qualifies as "complex" and thereby included in the metric for this incentive?

c. Please describe how the Company currently estimates ISR project costs, including who is responsible for the cost estimates and what data sources are used to develop the estimates.

d. Please discuss whether the Complex Capital Projects Capital Cost Incentive would create an implicit incentive for the Company to over-estimate project costs in order to ensure that the delivered cost would be less than the estimate?

e. Has the Company reviewed its historical accuracy in estimating complex capital costs? If so, please describe the Company's historical accuracy, and provide supporting data if available. Please provide the requested data in machine-readable format with all formulas intact.

Response:

a. As discussed in the Company's response to Division 1-29 part a., National Grid defines "complex capital projects" as projects that require a Project Manager.

b. Please see the Company's response to Division 1-29 part a.

c. Complex projects in the Infrastructure, Safety, and Reliability Plan are estimated by the Company's Electric Project Estimating Group. The Electric Project Engineering Group utilizes unitized libraries (which are routinely reviewed and updated) to develop detailed cost estimates based on the scope of a project using Success Enterprise estimating software. Project teams use a risk register to set appropriate project contingencies. The project teams reviews final estimates, and the estimates go through a quality control process prior to being released to the project manager for sanction. Cost data, completed project data, US Geological Survey, and other commercially available data are used in addition to the Success Enterprise libraries, when necessary.

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d. The Company's Electric Project Estimating Group performs estimates according to national standards set forth by AACE International and the American Society of Professional Estimators. In addition, the Electric Project Estimating Group uses risk registers to assess risk on a project to apply appropriate contingency based on project scope. Over-estimating for the purpose of the cost incentive would have a negative impact on the Company's ability to meet annual budget and portfolio delivery goals.

e. The tables below provide comparisons of sanctioned and actual project costs over the last four years. Review of the portfolio shows consistent estimating practice with the goal of reaching "0" but falling just below or above the target. The Electric Project Estimating Group monitors the portfolio to ensure estimates are not too aggressive or conservative in assumptions. Attachment DIV 3-6 provides the supporting data and calculations in machine-readable format.

CAPEX Pivot

Row Labels	Count of Project	Sum of Sanction CAPEX	Sum of Actual CAPEX	Sum of (Sanction CAPEX - Actual CAPEX)/Sanction CAPEX
2014	2	$5,191.00	$4,887.24	5.85%
2015	4	$4,874.00	$5,323.08	-9.21%
2016	8	$11,188.00	$10,811.27	3.37%
2017	4	$15,616.00	$15,523.15	0.59%
Grand Total	**18**	**$36,869.00**	**$36,544.74**	**0.88%**

Total (CAPEX+OPEX+COR) Pivot

Row Labels	Count of Project	Sum of Total Sanction	Sum of Total Actuals	Sum of (Total Sanction - Total Actuals)/Total Sanction
2014	2	$5,262.09	$5,085.93	3.35%
2015	4	$5,423.00	$5,632.97	-3.87%
2016	8	$11,396.00	$11,223.01	1.52%
2017	4	$15,662.08	$15,832.76	-1.09%
Grand Total	**18**	**$37,743.18**	**$37,774.67**	**-0.08%**

(This response is identical to the Company's response to Division 10-6 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

Project	Project Description	Closure Year (includes case where all work orders are closed, but Funding Project is opened)	Baseline - CAPEX Sanction Amount Data Source	Sanction CAPEX (baseline data)	Actual CAPEX
C036230	Langworthy Substation (D-Sub)	FY15	USSC-12-444vdtd Jan 1 2014	$1,574	$1,682
C033535	Johnston Sub 12.47 kV Expansion	FY16	USSC0110W259 v3 dtd June 20th 2015	$4,284	$4,590
C034002	Johnston Sub 12kV Expansion Getawa.	FY15	USSC0110W259 v3 dtd June 20th 2015	$326	$318
CD00659	Eldred Sub Asset Replacement(D-Lin	FY16	USSC-1 1-045v4 dtd 3/4/2014	$148	$244
C036232	Langworthy Substation (D-Line)	FY16	USSC-12-444vdtd Jan 1 2014	$116	$172
C046832		FY17	USSC-12-085 v3 dtd Dec 9th 2014 - did not include resanction paper	$389	$425
CD01243	Pontiac substation Flood Restoratio	FY17	USSC-12-433 v3 dtd 9/9/14 - did not look at resanction paper	$473	$593
C024180	Coventry MITS (Dist Line)	FY17	USSC0408P37 dtd June 13th 2012	$775	$678
C046398	Memorial Blvd Easton's Beach inst d	FY17	USSC-14-123 v2 dtd Nov 10th 2015 - did not include resanction paper	$1,390	$1,440
C046831	CLARKE 65J12 Feeder Upgrade (D-Sub)	FY17	USSC-12-085 v3 dtd Dec 9th 2014 - did not include resanction paper	$2,130	$2,172
CD01242	Pontiac substation Flood Restoratio	FY17	USSC-12-433 v3 dtd 9/9/14 - did not look at resanction paper	$2,811	$3,080
C054788	ValleySub 102 NERC CIP v3.25	FY17	Electronic DoA dtd May 2 2014. DOA was used from orignal electronic sanction, not re-sanction	$250	$317
C024179	Coventry MITS (Dist Sub)	FY17	USSC0408P37 dtd June 13th 2012	$2,970	$2,106
CD01104	Kent County 2nd Transformer (D-Line	FY18	USSC-12-355 v4 dtd Feb 23rd, 2016	$212	$167
C049981	Nsnvlle 127W41 New Customer Load	FY18	Originally, the project was less than $1M so there is only electronic DOA in PowerPlan. Project was resanctions. Amounts reflect original sanction	$700	$1,696
C023852	Inst Ductline Governor St. Prov.	FY18	USSC-13-239 dtd 8/20/2013	$1,571	$1,528
CD00972	New Highland Drive Substation - DSu	FY18	USSC 12-287 v4 dtd July 23rd, 2014	$13,133	$12,132

CAPEX Pivot

Row Labels	Count of Project	Sum of Sanction CAPEX	Sum of Actual CAPEX	Sum of (Sanction CAPEX - Actual CAPEX)/Sanction CAPEX
2014	2	$5,191.00	$4,887.24	5.85%
2015	4	$4,874.00	$5,323.08	-9.21%
2016	8	$11,188.00	$10,811.27	3.37%
2017	4	$15,616.00	$15,523.15	0.59%
Grand Total	**18**	**$36,869.00**	**$36,544.74**	**0.88%**

Total (CAPEX+OPEX+COR) Pivot

Row Labels	Count of Project	Sum of Total Sanction	Sum of Total Actuals	Sum of (Total Sanction - Total Actuals)/Total Sanction
2014	2	$5,262.09	$5,085.93	3.35%
2015	4	$5,423.00	$5,632.97	-3.87%
2016	8	$11,396.00	$11,223.01	1.52%
2017	4	$15,662.08	$15,832.76	-1.09%
Grand Total	**18**	**$37,743.18**	**$37,774.67**	**-0.08%**

Project	Project Description	FP Status	FP Completion Date	Closure Year (includes case where all work orders are closed, but Funding Project is opened)	WO Status	Total Cost	Source	Sanction CAPEX	Sanction OPEX	Sanction CoR	Total Sanction	Actual CAPEX	Actual OPEX	Actual CoR	Total Actuals
C052708	Volt Var-Substation	open			completed	$239.22	USSC-14-009 dtd July 12th 2016	$228.00	$0.00	$0.00	$228.00	$231.80	$7.73	$0.00	$239.53
C049981	Nsnvlle 127W41 New Customer Load	open	11/03/17	2017	3 Closed	$1,985.90	Originally, the project was less than $1M so there i	$700.00	$18.00	$10.00	$728.00	$1,696.07	$196.52	$93.32	$1,985.90
C053111	Volt Var - IT/IS	open			completed	$1,494.19	USSC-14-009 dtd July 12th 2016	$1,222.00	$177.00	$70.00	$1,469.00	$1,309.88	$177.14	$6.79	$1,493.82
CD00649	Gate 2 Substation (D-Sub)	open			1 closed 1 Op	$1,900.27	USSC-14-262 v2 dtd Feb 10th 2016; bundled with /	$1,804.00	$51.00	$35.00	$1,890.00	$2,189.46	$56.97	$322.73	$2,569.15
C046386	BITS Wakefield Sub Upgrades (D-Sub)	in service			in service	$2,837.06	US5C13-007v3 dtd May 23rd, 2016	$2,009.00	$22.00	$11.00	$2,042.00	$2,735.41	$0.08	$102.24	$2,837.74
CD01101	Kent County 2nd Transformer (D-Sub)	open			1 completed :	$2,445.87	USSC-12-355 v4 dtd Feb 23rd, 2016	$2,850.00	$19.00	$31.00	$2,900.00	$2,429.12	$17.09	$14.63	$2,460.85
C046352	Volt Var Dline RI Pilot Project	open			7 closed, 1 ca	$5,264.10	USSC-14-009 dtd July 12th 2016	$4,387.00	$475.00	$98.00	$4,960.00	$4,625.79	$590.72	$134.55	$5,351.06
CD00972	New Highland Drive Substation - DSu	open	11/03/17	2017	closed	$12,144.04	USSC 12-287 v4 dtd July 23rd, 2014	$13,133.00	$0.00	$0.00	$13,133.00	$12,132.08	$11.96	$0.00	$12,144.04
C023852	Inst Ductline Governor St. Prov.	open	11/03/17	2017	Closed	$1,532.78	USSC-13-239 dtd 8/20/2013	$1,571.00	$0.08	$0.00	$1,571.08	$1,527.54	$0.00	$5.25	$1,532.78
C024176	Chase Hill Sub (D-Sub)	open			in-service/car	$10,445.68	USSCO4O8P36v6 dtd June 10 2015	$9,916.00	$0.07	$0.04	$9,916.11	$10,472.32	$31.41	$0.48	$10,504.21
C068946	Flood Mitigation West Howard	open			Closed - appe	$0.00						$ 0.00	$ -	$ -	

NERI 4-12

Request:

Did the Company evaluate the impact of the proposed incentives on the Company's overall risk profile as relates to earning and exceeding revenue requirements? If yes, what were the results of the evaluation?

Response:

The proposed incentive portfolio is one of many variables that will impact investor perceptions of the Company's risk, particularly as the power sector transformation (PST) described in the PST Phase One Report – which contemplates a number of changes in the utility regulatory framework – advances. Any change in the regulatory framework, and the interactions between those changes, will impact investor perceptions of risk, as will expectations around future changes.

As Schedule PST-1, Chapter 9 – Performance in PST Book 1 describes, the integration of PST objectives into the utility business environment requires electric distribution utilities to perform new functions that are materially different from its traditional business functions, and will require innovation with regard to technology adoption and deployment, business and management practices, and the customer relationship. There is incremental risk associated with such innovation, and there is therefore little incentive for utilities to undertake it under the current regulatory framework. The Company has proposed performance incentives that the Company believes will support the PST objectives and provide a framework that encourages the Company to innovate in support of broader policy goals and beneficial customer outcomes that expand beyond the Company's core performance obligations.

(This response is identical to the Company's response to NERI 21-12 in Docket No. 4770)

NERI 4-13

Request:

Did the Company evaluate any other efforts and/or outcomes for developing additional incentives? If yes, please describe those additional efforts and/or outcomes, and why they were not proposed as PBIs.

Response:

The Company considered a number of additional performance incentive mechanisms that were included in the Power Sector Transformation (PST) Phase One Report, but did not include them in its proposal for the reasons noted below:

Time-varying rate participation: This may be a valuable metric for a performance incentive mechanism when such rates are more broadly enabled by advanced metering functionality (AMF);

Access to customer information: There is potential value in an incentive related to access to customer information, but that would be best developed as AMF deployment advances;

Participation in income eligible rate plan: Development of a performance incentive focused on programs for income eligible customers may be valuable following implementation of the Company's proposals affecting income eligible customers;

Customer engagement: Although the Company has not proposed a broad customer engagement performance incentive mechanism as described in the PST Phase One Report, it has developed performance incentive mechanisms to support customer engagement in specific contexts, such as the EV off-peak charging rebate, demand response programs, and AMF deployment.

(This response is identical to the Company's response to NERI 21-13 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-14

Request:

Has the Company evaluated the value of "scorecard metrics" to begin tracking data on behaviors and outcomes that may not yet be ready for treatment with earnings incentives?

Response:

The Company's focus in this proposal was to develop holistic portfolio of incentives to drive innovation, generate new benefits for customers, and support achievement of state policy goals. The Company did not evaluate specific scorecard metrics in the development of this proposal; however, there could be value in tracking additional metrics of interest to regulators and policymakers. Such metrics must be carefully defined to maximize their value and to minimize administrative burdens.

(This response is identical to the Company's response to NERI 21-14 in Docket No. 4770)

NERI 4-15

Request:

For each performance incentive the Company proposes, please provide a list and description of the specific data and metrics that the Company will track and report.

Response:

Please see the Company's response to Division 8-4, which is provided in Attachment NERI 4-15.

(This response is identical to the Company's response to NERI 21-15 in Docket No. 4770)

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4780
Responses to Division's Eighth Set of Data Requests
Issued February 20, 2018

Division 8-4

Request:

For each performance incentive mechanism, please describe how the determination of the target achievement (and subsequent reward) will be calculated and confirmed?

Response:

As part of its annual Power Sector Transformation reconciliation filing, for each performance incentive mechanism target, the Company will report its performance relative to the target, identify achieved savings and benefits, and display calculations for each incentive earned, including proration of any incentives related to metric achievement between the minimum, midpoint, and the maximum target levels. The Company will also provide explanations for any targets not achieved. The Company describes the specific data that it will report for each performance incentive below.

- Monthly Transmission Peak Demand Reduction: The Company will report and demonstrate the calculations for the annual sum of reductions in the weather normalized monthly peaks on a year-over-year basis. The loads to be weather normalized will be those used in calculating monthly ISO-NE Regional Network Service (RNS) billings. For 2019, for example, the Company will report the difference between the sum of weather normalized monthly peak demands for 2018, and the sum of weather normalized monthly peak demands for 2019.

- Forward Capacity Market Peak Demand Reduction: The Company will report and demonstrate the calculations for the reductions in the weather-normalized annual peak load on a year-over-year basis, using the same data as discussed above. For 2019, for example, the Company will report the difference between the weather normalized annual peak demand for 2018, and the weather normalized annual peak demand for 2019.

- EV Residential Off-Peak Charging Rebate Participation: The Company will report the number of customers enrolled in the Company's proposed rebate program for off-peak EV charging as of the end of the calendar year and evaluate this number against the target for the calendar year.

- DG Friendly Substation Transformer: The Company will report the number of substation transformers that have ground fault detection (3V0) installed as of the end of the calendar year.

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

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- Demand Response - Connected Solutions Participation: The Company will report the number of residential customers participating in the Company's Connected Solutions program.

- Demand Response – Commercial and Industrial (C&I) Participation: The Company will report the number of contracted MWs in the Company's C&I demand response programs.

- Electric Heat: The Company will report the annual CO_2 reductions in metric tons attributable to the ground-source heat pump and equipment incentives being offered under the Electric Heat Initiative. As discussed in the Company's response to Division 8-18, because of the costs and complexities of directly metering customer heating system use, the Company does not propose to directly measure CO_2 reductions of the Electric Heat Initiative, but rather to assign deemed CO_2 savings values to each type of conversion. Total deemed CO_2 savings realized through each year of the program will be a function of how many conversions of each system type are delivered each year.

- Electric Vehicles: The Company will report the incremental increase – above levels predicted by the Company – of personal electric vehicles registered in the Company's service territory on annual basis. Electric vehicles will include both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). The Company will report the total number of new registrations in Company service territory during the calendar year, using data from the R.L. Polk Vehicles in Operation data source, in comparison with the Company's projections shown in Worksheet 9.3, reproduced here as Attachment DIV 8-4. Please see Row 17, Columns K through M, for the forecast values that will be used to demonstrate whether the Company's targets have been achieved.

- Behind the Meter Storage: The Company will report incremental MW of installed behind-the-meter storage for the preceding calendar year.

- Company-Owned Storage: The Company will report the incremental MW of Company-owned storage installed during the preceding calendar year in support peak reduction or provide system benefits. The Company expects to provide a clear demonstration of peak reduction or system benefits in order to earn the incentive.

- AMF Customer Engagement: For the preceding calendar year, the Company will indicate whether the relevant milestone or target for that year was achieved. Relevant milestones/targets are shown below. For 2021, the Company expects to quantify the number of meter installations to demonstrate achievement of the 30 percent deployment target. Additional discussion of these milestones is provided in Schedule PST-1, Chapter 9 – Performance on Bates Page 175 of PST Book 1.

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

Year	Milestones	Basis Points
2019	Deliver customer engagement plan	2
2020	Conduct and report on customer awareness survey	1
2020	Commence mass scale meter deployment	1
2021	Achieve 30% deployment and customer portal access	2

- VVO Pilot Delivery: For 2019, the Company will report whether the project is in service. For 2020 and 2021, the Company will report and demonstrate whether the incremental one percent reduction in energy consumption and peak demand in addition to what is expected from primary VVO/CVR optimization has been achieved.

- Interconnection Support - Time to Interconnection Service Agreement (ISA): The Company will report the percent difference between: (1) the aggregate number of business days allowed by the Interconnection Tariff to provide an executable ISA over all processes; and (2) the average time measured in business days necessary for the Company to provide a customer with an executable ISA, commencing from the date a completed application is received, over all processes.

- Interconnection Support - Average Days to System Modification: The Company will report the percent difference between: (1) the total aggregate number of business days allowed by the Interconnection Tariff to complete system modifications, over all processes; and (2) the average time measured in business days necessary for the Company to complete system modifications, commencing from the date of execution of the ISA, over all processes.

- Interconnection Support - Estimate Versus Actual Costs: The Company will report the overall percent difference between the sum of costs estimated by the Company for interconnection and the sum of the actual costs paid by interconnecting customers.

(This response is identical to the Company's response to Division 25-4 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2	**Electric Vehicles Target Calculation**												
3	Registered EVs in Company's RI Territory -- Summary of Polk Data												
4	Row Labels	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 YTD**	**2018**	**2019**	**2020**	**2021**
5	BEV(PEV)				32	41	117	193	293				
6	HEV(PHEV)				178	182	413	538	733				
7	HV(NP_HEV)				8669	9070	10425	10985	11613				
8	Grand Total				8879	9293	10955	11716	12639				
9													
10	Cumulative EV Registrations with Projections Based on AEO 2017 EV Sales Growth for New England									*Forecast*			
11	BEV				32	41	117	193	293	463	706	1,049	1,537
12	PHEV				178	182	413	538	733	1,041	1,448	1,983	2,688
13	Total Ev				210	223	530	731	1026	1,505	2,153	3,032	4,225
14													
15	Annual New BEV Registrations					9	76	76	100				
16	Annual New PHEV Registrations					4	231	125	195				
17	Annual New EV Registrations Total					13	307	201	295	*479*	*648*	*879*	*1,193*
18													
19	Annual New Registrations												
20			Actual			*Forecast (includes annualized YTD number for 2017)*							
21	**BEVs - Incremental**		2015	2016	**2017**	**2018**	**2019**	**2020**	**2021**				
22	Actuals and Forecast		76	76	120	170	242	344	488				
23													
24			Actual			*Forecast (includes annualized YTD number for 2017)*							
25	**PHEVs - Incremental**		2015	2016	**2017**	**2018**	**2019**	**2020**	**2021**				
26	Actuals and Forecast		231	125	234	308	406	535	705				
27													
28						New registrations target based adjustment of forecast (includes forecast)							
29	**Growth Assumptions Based on AEO 2017**						**2019**	**2020**	**2021**				
30	**(CAGR of EV Sales, New England, 2017-2021)**					Min	778	1,055	1,432	120% of forecast prediction			
31	BEV	0.419903375				Target	908	1,230	1,670	140% of forecast prediction			
32	PHEV	0.317319663				Max	1,167	1,582	2,148	180% of forecast prediction			
33	Total	0.367908739											
34													
35						Incremental Annual New Registrations (above forecast)							
36							**2019**	**2020**	**2021**				
37						Min	130	176	239	120% of forecast prediction			
38						Target	259	352	477	140% of forecast prediction			
39						Max	519	703	954	180% of forecast prediction			

NERI 4-16

Request:

Did the Company consider developing a PBI to incentivize avoiding capital projects in the ISR, rather than reducing the cost of projects already proposed? Did the Company also consider a PBI for avoiding distribution line projects and maintenance, instead of an incentive for reducing cost-per-mile of completed projects?

Response:

The Company's proposed capital efficiency incentives are intended to encourage the Company to identify new efficiencies in the delivery of approved capital investments that have the potential to generate meaningful savings for customers over time. As the Company discusses in Schedule PST-1, Chapter 9 – Performance (see Bates Page 164 of PST Book 1), the current regulatory framework does not reward the utility for identifying and delivering such efficiencies.

The Company notes that one of its approved incentives in the 2018 System Reliability Procurement (SRP) Plan would allow the Company to share 20 percent of the net benefits (using the Utility Cost test) of distributed energy resources installed due to SRP initiatives. The Company is interested in proposing additional incentives for non-wires alternatives in the future and expects to continuously evaluate opportunities to propose such mechanisms in future proceedings.

(This response is identical to the Company's response to NERI 21-16 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

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NERI 4-17

Request:

Reference Chapter 4, p. 9. How did the Company determine that the cap on retained savings should be $2.5 million on expected yearly budgets of $5-$15 million? Does the Company have reason to believe it is overspending by 30% or more on Complex Capital Projects?

Response:

Please see Attachment NERI 4-17, which is the Company's response to Division 1-30.

There is no evidence that the Company is overspending on complex capital projects. This incentive is intended to encourage the Company to devote resources to identifying new efficiencies that will result in customer savings.

(This response is identical to the Company's response to NERI 21-17 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

Division 1-30

Request:

Please provide the rationale behind the $2.5 million cap on the value of savings that might be retained by the Company from the Complex Capital Projects Capital Cost Incentive.

Response:

Narragansett Electric sought to propose an incentive structure for complex capital projects that would balance customer and Narragansett Electric's interests. Narragansett Electric believes that it is reasonable to propose an upper bound to the incentive beyond which all further savings would be returned to customers. The $2.5 million cap was chosen because it represents a significant revenue opportunity for Narragansett Electric that will motivate its performance while also providing 50 percent of the savings to customers until the threshold is reached, and 100 percent of the savings to customers for savings above the cap.

(This response is identical to the Company's response to Division 5-30 in Docket No. 4770.)

Prepared by or under the supervision of: Meghan McGuinness and Timothy R. Roughan

NERI 4-18

Request:

Why are PBIs necessary for programs or policies currently underway or pending Commission approval? In particular, please reference the existing/pending programs described on Chapter 9, p. 14, regarding the incentive for the delivery of the VVO pilot, and Chapter 9, p. 10, regarding the DG substations incentive for the 3V0 program already submitted in an ISR filing. What incremental or additive actions by the Company will ratepayers be incentivizing through the PBIs proposed in the PST plan?

Response:

Performance-based incentives are in these instances being proposed to reward the Company for the successful delivery of innovative efforts that are specifically targeted at integrating new technologies, advancing state policy goals, and generating new benefits for customers. The growing importance of emerging energy technologies, the ambition of Rhode Island's clean energy and environmental policy goals, and the need for creative thinking to achieve energy goals that often require action outside the traditional purview of state regulators all require additional innovation in the utility industry. A regulatory environment that rewards innovation is necessary for customers to benefit from new technologies creative policies.

Statutory programs to encourage and facilitate the development of renewable energy in Rhode Island support the use of incentives to encourage innovation, align the interests of customers and utilities, and direct the attention of utilities toward specific policy goals. The Public Utilities Commission has previously approved Company tariffs implementing these statutory programs that allow for the collection of performance incentives associated with the procurement of long-term renewable energy contracts for retail customers, both from wholesale power providers and, separately, from eligible distributed-generation projects (the latter under the Renewable Energy Growth Program).

With respect to the immediate impacts of the two incentives discussed in the question, the DG-Friendly Substation Transformer incentive will encourage the Company's timely delivery of ambitious installation goals included in Narragansett Electric's annual Infrastructure, Safety, and Reliability Plan, and would reward the Company for successfully implementing a fundamental design shift in proactively installing these system upgrades to advance interconnection of large quantities of distributed generation to support Rhode Island's clean energy and climate goals.

The VVO Pilot Delivery incentive will reward the Company for the efforts necessary to ensure that the project delivers the expected system benefits. Successful project delivery reflects the Company's commitment both to ensuring this project provides the greatest benefits to the system, and to maximizing this opportunity to derive lessons learned in support of AMF deployment and state policy goals.

Finally, it is important to consider the dynamic impacts of a regulatory framework that includes performance incentives, and how incentives can benefit customers and support state policy goals beyond the immediate proceeding. The existence of incentives that reward the Company for successfully delivering innovative programs that support state policy goals and deliver new benefits for customers will encourage the Company to develop new innovative programs going forward, due to the Company's knowledge that there is potential to be rewarded for such innovation. This dynamic effect will accelerate the development and deployment of new programs, to the benefit of customers and the system as a whole.

(This response is identical to the Company's response to NERI 21-18 in Docket No. 4770)

NERI 4-19

Request:

Reference Chapter 4, p. 10-11, regarding the DG-Friendly Substation Transformer.

a. Please describe what actions by the Company will be incentivized by the DG-Friendly Substation Transformer PBI that are not incented by the suite of Interconnection PBIs or current Company practice.

b. Did the Company consider an outcome-based metric, such as the amount of increased DG installed by customers resulting from the work, rather than the amount of work completed by the Company?

Response:

a. Please see the Company's response to NERI 4-18.

b. Please see the Company's response to NERI 4-5.

This response is identical to the Company's response to NERI 21-19 in Docket No. 4770)

NERI 4-20

Request:

Reference the Company's statement in Chapter 4, p. 20, that "The Company has proposed the largest incentive around the DG-Friendly Substation metric. The Company's proactive installation of 3V0 has the potential to expedite interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits described above. However, the Company has not quantified the net benefits to customers from these efforts, due to the assumptions that would have to be made about the timing of distributed generation installations absent these investments, the number and size of installations accelerated, and the specific technology being installed." Please explain why the DG-Friendly Substation Transformer metric is allocated a large number of potential basis points if the customer benefit has not been calculated.

Response:

As the Company noted on Bates Page 168 of PST Book 1, the Company assigned values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due the activity encouraged by the incentive. The Company has supported the proposed values for individual incentives using analyses of benefits and costs where possible. Where quantification is not possible, the Company has provided a qualitative description of the most significant benefits and costs.

The Company has allocated up to 10 basis points for this metric at the maximum target levels because of this metric's direct support of the State's renewable energy goals, and in recognition of the role that these investments will play in support of accelerating the benefits from distributed generation. The Company is committed to supporting a carbon-free future and realizes this is a fundamental design shift needed to advance interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits from these resources, including reductions in CO_2 and criteria pollutant emissions, avoided energy and capacity costs, and avoided renewable energy credit costs. The Company has allocated more basis points to this metric than other distributed energy resource metrics in recognition of its importance to the State's renewable energy goals.

(This response is identical to the Company's response to NERI 21-20 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

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NERI 4-21

Request:

For performance incentive programs that do not currently have set targets, how did the Company allocate basis points?

Response:

Two performance incentives mechanisms (Demand Response – Connected Solutions Participation and Demand Response – C&I Participation) fall into this category. As the Company states on Bates Page 172 of PST Book 1, the basis points included in Tables 9-5 and 9-6 (Bates Page 172 of PST Book 1) were intended to be illustrative of the potential size of the incentive.

(This response is identical to the Company's response to NERI 21-21 in Docket No. 4770)

NERI 4-22

Request:

For each performance incentive the Company proposes, how did it calculate basis points in proportion to customer savings?

Response:

As the Company discussed in Schedule PST-1, Chapter 9 – Performance of PST Book 1 (see Bates Page 168), the Company assigned values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due to the activity encouraged by the incentive. The Company has supported the proposed values for individual incentives using analyses of benefits and costs where possible. Where quantification is not possible, the Company has provided a qualitative description of the most significant benefits and costs. Where the Company has quantified benefits or savings, the Company has sought to allocate basis points such that customers retain the majority of quantified benefits or savings. One exception to this approach is the Electric Heat performance incentive mechanism, for which the Company's proposed basis points implies that customers would retain only about 25 percent of the quantified net benefits. The reason for this is that the Electric Heat Initiative provides important economic development benefits that have not been quantified in the benefit-cost analysis. In particular, the program will support the growth in the State of a labor-intensive sector with a direct positive impact on the building trades.

Please see the Company's responses to Division 3-9 through Division 3-23 in this docket for additional discussion of the basis point allocation for each performance incentive mechanism.

(This response is identical to the Company's response to NERI 21-22 in Docket No. 4770)

NERI 4-23

Request:

Reference Chapter 9, p. 13, regarding Behind-the-Meter Storage. Please describe:

a. What action will the Company be incentivized to perform with regard to behind the meter storage?

b. What metrics will the Company use to track and evaluate the program?

c. Does the Company have any current or potential programs for promoting behind-the-meter storage independent of this PBI?

Response:

a. This incentive will encourage the Company's to work proactively with interested customers to evaluate opportunities for storage.

b. The Company does not currently have a program (and associated metrics) for behind-the-meter storage. For the purposes of this performance incentive mechanism, the Company will track and report incremental MW of installed behind-the-meter storage for the relevant calendar year.

c. As noted above, the Company does not currently have a program to encourage behind-the-meter storage. The Company indicated in its Annual Energy Efficiency Plan for 2018 (Docket No. 4755) that it will conduct consumer research to better understand customer driven needs and opportunities for the intersection of distributed generation, battery storage, and electric vehicles, including an examination of viable consumer packages and price points to help inform the design a pilot in program year 2019.

(This response is identical to the Company's response to NERI 21-23 in Docket No. 4770)

NERI 4-24

Request:

Reference Chapter 9, p. 12, regarding the Electric Heat Initiative. Will the Company's natural gas customers be eligible and targeted for beneficial heat electrification?

Response:

Eligibility for the Electric Heat Initiative is based on the benefit-cost analysis undertaken in support of the initiative and was limited to conversions with a Societal Cost Test ratio greater than 1. Under all scenarios, converting from natural gas to heat pumps fails to generate a positive Societal Cost Test result because of negligible participant cost savings or CO_2 emissions reductions. Therefore, natural gas conversions are not supported by the Electric Heat Initiative.

(This response is identical to the Company's response to NERI 21-24 in Docket No. 4770)

NERI 4-25

Request:

Please provide the program costs associated with the Electric Heat and Electric Vehicle Initiatives. Please confirm that those costs are incorporated in the Company's revenue requirement.

Response:

Please see Workpaper 5.1 (Electric Vehicles) and Workpaper 6.1 (Electric Heat) in PST Book 3 (Bates Pages 45-57 and 58-63, respectively) for program costs. These costs are incorporated in the Company's revenue requirement.

(This response is identical to the Company's response to NERI 21-25 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-26

Request:

Reference Chapter 4, p. 16, regarding the Interconnection Support — Estimate versus Actual Cost. Please describe how the Company will develop the "sum of costs estimated by the Company for interconnection."

Response:

The "sum of costs estimated by the Company for interconnection" will be determined by taking, for all projects over $50,000, the Company's estimated costs for interconnection for each application received in a given calendar year, and summing those estimates over all applications received in that calendar year.

(This response is identical to the Company's response to NERI 21-26 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

NERI 4-27

Request:

Has the Company accounted or controlled for the possibility that the DG-Friendly Substation Program and the suite of Interconnection incentives may result in double-incenting the same outcomes *(e.g.*, decreased costs and time required for interconnection)?

Response:

Although the DG-Friendly Substation Program may lead to reductions in the costs of interconnection and the time required for interconnection, neither of those outcomes is a performance incentive mechanism proposed by the Company. The Company has proposed a metric (Average Days to System Modification) that is focused on improving the Company's performance against the timelines permitted by the Interconnection Tariff for system modifications. Although the Company's installation of 3V0 may lead to reductions in the timeline necessary for system modification, the Average Days to System Modification metric and incentive remains valuable because it encourages the Company to take a holistic view of process improvements that can be made to minimize the timelines to system modification, and ultimately, interconnection of distributed resources in support of Rhode Island's renewable energy and CO_2 reduction goals. To the extent that that 3V0 already being present at a substation or transformer means that an interconnecting customer would not need to incur the cost or delay of a 3V0 upgrade, the other system modifications necessary to complete an interconnection would still need to be constructed.

(This response is identical to the Company's response to NERI 21-27 in Docket No. 4770)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness