Docket No. 4780
Second Set of Data Requests of the
Sierra Club, People's Power & Light and
Natural Resources Defense Council
March 6, 2018

Storage

2-1. Referring to Chapter 7 (Energy Storage), regarding scale of the Company's proposed storage initiative, please provide any analyses the Company consider that indicate the amount of storage and timing needed to achieve of the greenhouse gas reduction targets in the Resilient Rhode Island Act.

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

2-2. In 2016, the Massachusetts Department of Energy Resources produced a State of Charge report (available at http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf) with a finding that a large-scale (1,766 MW) storage program would produce a BCR of 1.7 to 2.4 accounting for system benefits alone (see pp. 103-104). The report suggested a goal by 2025 of 600 MW. Massachusetts now has a goal of 200 MW of storage by 2020.

a. Please identify the basis for the difference between the Benefit Cost Ratio (BCR) found in the Massachusetts report and the BCR of 0.45 indicated in the Company's proposal for Docket No. 4780.

b. Please explain whether the Company believes that storage can be cost-effectively implemented on a scale comparable to (i.e., adjusted for load) the scale contemplated in the Massachusetts State of Charge report.

c. Please identify whether and how the Company believes that its proposal would place Rhode Island on a path to large-scale deployment of storage by 2025.

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

2-3. Referring to Chapter 7 (Energy Storage), page 137, what does National Grid hope to learn from its 2 MWh of proposed energy storage in Rhode Island that is different from or additive to what it intends to learn from its 15 MWh of energy storage in Massachusetts that it already owns or is in the process of installing?

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

2-4. Referring to Chapter 7 (Energy Storage), does the Company envision applying lessons learned from the storage pilot to programming within the energy efficiency and system reliability plans which are reviewed by the Efficiency Collaborative and Energy Efficiency Resource Management Council? If so, how?

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

2-5. Referring to Chapter 7 (Energy Storage), did the Company consider a program similar to the Green Mountain Power (Vermont) program coupling PowerWall storage devices with solar? Please explain why the Company did not propose such a configuration.

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

2-6. Referring to Chapter 7 (Energy Storage), did the Company consider coupling storage with Electrical Vehicle Supply Equipment, particularly DC Fast Charging stations? If not, why not?

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

2-7. Referring to Chapter 7 (Energy Storage), for storage developed as part of the Company's proposal, how does the Company plan on sharing control of storage facility with the customer? Would the customer be able to discharge the stored power in their sole discretion to optimize benefits on their side of the meter?

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

Solar for Income-Eligible

2-8. Referring to Chapter 8 (Income Eligible) at page 154 and the BCA in Appendix 2-1, page 63, the Company indicates a benefit of $1,605,107 for avoided Greenhouse Gas (GHG) Externality Costs. However, according to comments made at the February 21 technical session, the Company stated that it will either use Renewable Energy Credits (RECs) from the projects for compliance with the Renewable Energy Standard or sell the RECs into the compliance market. In either case, all environmental attributes, including GHG reduction, will be attached to the RECs. If the RECs are not retired separately from the compliance market, please clarify why it would be appropriate to account for GHG reductions as a benefit of this program. Please recalculate the BCA for this program with the GHG benefits removed.

Response can be found on Bates page(s) 8-28.

2-9 Referring to Chapter 8 (Income Eligible) at page 154, Table 8-3, the BCA model assumes a value of $213,002 for Avoided Renewable Energy Certificate cost. Please provide the assumptions used by the Company to calculate this value, including solar output and

market values for RECs over time. Please indicate whether the assumed market values for REC over time are consistent with the Company's plans for complying with the Renewable Energy Standard.

Response can be found on Bates page(s) 29-30.

Electric Vehicle Initiative

2-10 Please identify the types of incentives the Company believes are most effective to induce consumers to purchase or lease an electric vehicle (EV). Please explain how the Company's proposals in the Electric Transportation Initiative would be effective in inducing consumers to purchase or lease EVs. Specifically identify any aspects of the Company's proposal that would address the barrier of high upfront costs associated with the purchase of EVs at this time.

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

SC 2-1

Request:

Referring to Chapter 7 (Energy Storage), regarding scale of the Company's proposed storage initiative, please provide any analyses the Company consider that indicate the amount of storage and timing needed to achieve of the greenhouse gas reduction targets in the Resilient Rhode Island Act.

Response:

The Company does not anticipate that the proposed energy storage project will significantly impact the Resilient Rhode Island Act goals directly because it is a demonstration project. Therefore, the Company did no such analysis. However, energy storage has the potential to play an important role in supporting the Act's objectives and the Company's energy storage proposal supports those objectives.

Prepared by or under the supervision of: Carlos Nouel and James Perkinson

SC 2-2

Request:

In 2016, the Massachusetts Department of Energy Resources produced a State of Charge report (available at http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf) with a finding that a large-scale (1,766 MW) storage program would produce a BCR of 1.7 to 2.4 accounting for system benefits alone (see pp. 103-104). The report suggested a goal by 2025 of 600 MW. Massachusetts now has a goal of 200 MW of storage by 2020.

a. Please identify the basis for the difference between the Benefit Cost Ratio (BCR) found in the Massachusetts report and the BCR of 0.45 indicated in the Company's proposal for Docket No. 4780.

b. Please explain whether the Company believes that storage can be cost-effectively implemented on a scale comparable to (i.e., adjusted for load) the scale contemplated in the Massachusetts State of Charge report.

c. Please identify whether and how the Company believes that its proposal would place Rhode Island on a path to large-scale deployment of storage by 2025.

Response:

a. The Company does not have access to the Massachusetts Department of Energy Resources' methodology used to calculate the BCR in its State of Charge. The Company developed a Rhode Island-specific BCA methodology consistent with the Public Utilities Commission's Docket 4600 Guidance Document.

b. The Company has not performed any analysis to determine if storage can be cost-effectively implemented in Rhode Island on a comparable scale to the scale contemplated for Massachusetts in the State of Charge report.

c. The Company's proposal is not designed to place Rhode Island on a path to large-scale deployment of storage by 2025. The proposed pilot is designed to allow the Company the opportunity to learn before the market for energy storage fully develops in Rhode Island. Specifically, in this proposal, the Company will focus on understanding the potentially conflicting goals between customer and utility and how to manage them for future third party owned systems. Efficiently accommodating these systems will help progress Rhode Island's clean energy goals.

Prepared by or under the supervision of: Carlos Nouel and James Perkinson

SC 2-3

Request:

Referring to Chapter 7 (Energy Storage), page 137, what does National Grid hope to learn from its 2 MWh of proposed energy storage in Rhode Island that is different from or additive to what it intends to learn from its 15 MWh of energy storage in Massachusetts that it already owns or is in the process of installing?

Response:

The proposed energy storage systems in Rhode Island are anticipated to be Company-owned and co-located with customer load behind the meter, making them unique to this proposal. This arrangement will allow the Company to explore operating control modes to balance local (partner) benefits with system-wide (utility) benefits.

SC 2-4

Request:

Referring to Chapter 7 (Energy Storage), does the Company envision applying lessons learned from the storage pilot to programming within the energy efficiency and system reliability plans which are reviewed by the Efficiency Collaborative and Energy Efficiency Resource Management Council? If so, how?

Response:

Lessons learned from the storage pilot will inform the Company's interconnection process as well as inform the Company about potentially necessary operational control methods and protocols that seek to maximize the value of the energy storage. As the necessary operational control methods and protocols should result in load relief on certain parts of the electric distribution system, it should also provide on-peak kW savings. The Company would apply lessons learned to any future storage-related project proposed in its energy efficiency and system reliability plans that will be reviewed by the Efficiency Collaborative and Energy Efficiency Resource Management Council.

SC 2-5

Request:

Referring to Chapter 7 (Energy Storage), did the Company consider a program similar to the Green Mountain Power (Vermont) program coupling PowerWall storage devices with solar? Please explain why the Company did not propose such a configuration.

Response:

The Company considered many different projects early in the process, including projects coupling PowerWall storage devices with solar, but elected to move forward with the co-located, behind the meter, storage and customer load proposal. The Company chose this option because it was an area not currently investigated by the Company and the Company would like to leverage its experience with larger capacity storage systems toward the storage goals outlined in Schedule PST-1, Chapter 7 – Energy Storage.

SC 2-6

Request:

Referring to Chapter 7 (Energy Storage), did the Company consider coupling storage with Electrical Vehicle Supply Equipment, particularly DC Fast Charging stations? If not, why not?

Response:

The Company considered many different projects early in the process, including coupling storage with Electric Vehicle Supply Equipment, but elected to move forward with the co-located, behind the meter, storage and customer load proposal. The Company chose this option because it was an area not currently investigated by the Company.

SC 2-7

Request:

Referring to Chapter 7 (Energy Storage), for storage developed as part of the Company's proposal, how does the Company plan on sharing control of storage facility with the customer? Would the customer be able to discharge the stored power in their sole discretion to optimize benefits on their side of the meter?

Response:

The Company intends to fairly compensate partners for physical use of space, Company operation of the energy storage device, as well as any bill impacts that may result due to the Company's research and development efforts. The customer may not have direct control over the Company-owned storage, but through pre-arranged agreements, the system may provide critical demand reduction or resiliency benefits, which would be negotiated directly with partners.

SC 2-8

Request:

Referring to Chapter 8 (Income Eligible) at page 154 and the BCA in Appendix 2-1, page 63, the Company indicates a benefit of $1,605,107 for avoided Greenhouse Gas (GHG) Externality Costs. However, according to comments made at the February 21 technical session, the Company stated that it will either use Renewable Energy Credits (RECs) from the projects for compliance with the Renewable Energy Standard or sell the RECs into the compliance market. In either case, all environmental attributes, including GHG reduction, will be attached to the RECs. If the RECs are not retired separately from the compliance market, please clarify why it would be appropriate to account for GHG reductions as a benefit of this program. Please recalculate the BCA for this program with the GHG benefits removed.

Response:

Avoided greenhouse gas (GHG) externality costs and avoided Renewable Energy Credit (RECs) costs are appropriately treated as separate benefits in the Company's benefit-cost analysis as each reflects the independent monetized values of distinct system impacts directly attributable to the proposed investment. These benefits are not double counted in the Company's BCAs. The non-embedded avoided GHG cost benefit included in the Company's benefit-cost analysis captures the avoided marginal cost of stabilizing carbon dioxide emissions at 80 percent below 1990 levels by 2050 resulting from offset marginal emissions from wholesale generation, while the avoided REC cost benefit captures the avoided monetary compliance cost to customers resulting from an administrative adjustment to the minimum amounts required under the Renewable Energy Standard (RES). Both benefits are included in Appendix B of the Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid (Docket 4600 Guidance Document), and both are included in the Rhode Island Test for evaluation of energy efficiency programs, and included here as Attachment SC 2-8. Please note the non-embedded avoided GHG cost benefit is included only in the societal cost test (SCT) and is not included in the rate impact measure (RIM) as it does not reflect a direct monetary cost to customers. The Company does not agree that the GHG benefit should be removed from the societal cost test.

Prepared by or under the supervision of: Carlos Nouel and James Perkinson

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4755
Attachment 4

2018 Rhode Island Test Description

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Introduction

This section has been prepared pursuant to Section 1.2(B) of the Least Cost Procurement Standards (Standards) for the procurement of energy efficiency resources, approved by the Rhode Island PUC in Docket 4684.

In previous Annual Plans, the Company assessed the cost-effectiveness of measures, programs, and portfolios according to the Total Resource Cost (TRC) Test. The revised Standards set forth new requirements for a cost-effectiveness test called the Rhode Island Benefit Cost Test (RI Test), which "more fully reflects the policy objectives of the State with regard to energy, its costs, benefits, and environmental and societal impacts." The change to the RI Test is a positive development for energy efficiency. Accounting for all costs and benefits associated with energy efficiency provides for a more holistic view of its impacts to electric and gas customers, the environment, and the economy. The 2018 Annual Plan includes two new benefits for cost-effectiveness screening that were approved as part of the 2018-2020 Three-Year Plan in Docket 4684. These benefits include: non-embedded greenhouse gas reductions (i.e., the value of reducing greenhouse gas emissions that is not already included in the baseline avoided costs) and economic development impacts.

The source for many of the avoided cost value components is "Avoided Energy Supply Costs in New England: 2015 Report," (2015 AESC Study) prepared by Tabors Caramanis and Rudkevich (TCR) for the Avoided Energy Supply Component Study Group, April 2015.[1] This report was sponsored by all the electric and gas efficiency program administrators in New England and is designed to be used for cost effectiveness screening in 2016 through 2018.

It is the intent of National Grid that the RI Test as described here will be in place until the next review of the Standards in advance of the 2020-2022 Least Cost Procurement Plan. However, additional benefits and costs may be added in future Annual Plans and the component values may be updated over the course of the three year period based on the availability of new study results. Future updates to inputs and values will be included in future Annual Plan filings.
As specified in the Standards,

[1] The report is available online at: http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf. This study forecasts avoided costs for three years, compared to prior studies which developed avoided costs applicable to a two-year period. In the fall of 2016, TCR prepared a limited update of Appendices B (Avoided Electricity Cost Results), C (Avoided Natural Gas Cost Results), and D (Avoided Electricity Cost Results) in the report for Maine, New Hampshire, Rhode Island, and Vermont based on new estimates for six categories of inputs starting in 2017 that the Company applied to the 2018-2020 Three-Year Plan and this 2018 Annual Plan.

i. The distribution company shall assess the cost-effectiveness of measures, programs, and portfolios according to a benefit-cost test that builds on the Total Resource Cost Test approved by the Public Utilities Commission (PUC) in Docket 4443, but that more fully reflects the policy objectives of the State with regard to energy, its costs, benefits, and environmental and societal impacts. The distribution company shall, after consultation with the Council, propose the specific benefits and costs to be reported, and factors to be included, in the Rhode Island Benefit Cost Test (RI Test) and include them in Energy Efficiency Plans. These benefits should include resource impacts, non-energy impacts, distribution system impacts, economic development impacts, and the value of greenhouse gas reductions, as described below. The accrual of specific non-energy impacts to only certain programs or technologies, such as income-eligible programs or combined heat and power, may be considered.

ii. The distribution company shall apply the following principles when developing the RI Test:

   a. **Efficiency as a Resource.** EE is one of many resources that can be deployed to meet customers' needs. It should, therefore, be compared with both supply-side and demand-side alternative energy resources in a consistent and comprehensive manner.

   b. **Energy Policy Goals.** Rhode Island's cost-effectiveness test should account for its applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives.

   c. **Hard-to-Quantify Impacts.** Efficiency assessment practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize.

   d. **Symmetry.** Efficiency assessment practices should be symmetrical, for example, by including both costs and benefits for each relevant type of impact.

   e. **Forward Looking**. Analysis of the impacts of efficiency investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of efficiency measures with those that would occur absent the efficiency investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

f. **Transparency.** Efficiency assessment practices should be completely transparent, and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

iii. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of CO_2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative. The RI Test shall also include any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. A comparable benefit for greenhouse gas reduction resulting from natural gas or delivered fuel energy efficiency or displacement may be considered. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above. The RI Test may also include the costs and benefits of other emissions and their generation or reduction through Least Cost Procurement.

iv. Benefits and costs that are projected to occur over the term of the Energy Efficiency Plans shall be stated in present value terms in the RI Test calculation using a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a discount rate that indicates that energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk. The discount rate shall be reviewed and updated in the Energy Efficiency Plans, as appropriate, to ensure that the applied discount rate is based on the most recent information available.

v. The distribution company shall provide a discussion of the carbon impacts efficiency and reliability investment plans will create, whether captured as benefits or not.

The Rhode Island Test Overview

The RI Test compares the present value of a stream of **net benefits** associated with the **net savings** of an energy efficiency measure or program **over the life** of that measure or program to the total costs necessary to implement the measure or program. The RI Test may be applied to any energy efficiency program independent of the primary fuel or resource the effort focuses on.

The RI Test captures the value created by efficiency measures installed in a particular program year over the useful life of the measure. The measure life is based on the technical life of the measure modified to reflect expected measure persistence. Because the RI Test captures the value associated with a stream of benefits over a

period of time, the benefits from a measure are present valued so that costs and benefits may be compared.

The benefits calculated in the RI Test are the avoided resource supply and delivery costs, valued at marginal cost for the periods when there is a load reduction, as well as the monetized value of non-resource savings.

The program costs are those paid by both the utility and by participants plus the increase in supply costs for any period when load is increased. All equipment, installation, O&M, removal, evaluation and administration costs are included.

All savings included in the value calculations are net savings. The expected net savings are typically an engineering estimate of savings modified to reflect the actual realization of savings based on evaluation studies. The expected net savings also reflect market effects due to the program. The RI Test captures the combined effects of a program on both the participating customers and those not participating in a program. From a resource acquisition perspective, if the program induces participants or non-participants to acquire energy efficiency devices without program expenditures, these effects—known as spillover—should be attributed as program benefits in the RI Test. The costs incurred by customers to acquire equipment on their own are also counted as costs in the RI Test.

On the other hand, if a customer accepts program funds to implement an energy efficiency measure they would have done anyway, the savings associated with this practice is known as "free ridership." From the perspective of resource acquisition through utility programs, it is important to distinguish whether the customer would have implemented the efficiency measure without the program. Therefore, savings associated with free-ridership are deducted from program savings.[2]

The benefits and costs considered in Rhode Island are detailed in the next section.

Description of Program Benefits and Costs

The following benefits and costs are included in the RI Test. They are listed here with details after.

1) Electric Energy Benefits
2) Electric Generation Capacity Benefits
3) Electric Transmission Capacity and Distribution Capacity Benefits

[2] Both free-ridership and spillover have been determined from surveys of program participants, non-participants, and other market actors

4) Natural Gas Benefits
5) Fuel Benefits (including the value of delivered fuel savings from programs that influence delivered fuel consumption)
6) Water and Sewer Benefits
7) Non-Energy impacts
8) Price Effects
9) Combined Heat and Power Benefits
10) Non-embedded Greenhouse Gas Reduction Benefits
11) Economic Development Benefits
12) Utility Costs
13) Participant Costs

All of the benefits are monetized benefits directly associated with the installation of electricity or natural gas efficiency projects.

1) Electric Energy Benefits

Avoided electric energy costs are appropriate benefits for inclusion in the RI Test. When consumers do not have to purchase electric energy because of their investment in energy efficiency, an avoided resource benefit is created.[3]

Electric energy savings are valued using the avoided electric energy costs developed in the 2015 AESC Study Update, Appendix B.[4] The values in the AESC Study represent wholesale electric energy commodity costs that are avoided when generators produce less electricity because of energy efficiency.[5] They include pool transmission losses incurred from the generator to the point of delivery to the distribution companies, the costs of renewable energy credits borne by generators, and a wholesale risk premium that captures market risk factors typically recovered by generators in their pricing. The avoided energy costs also internalize the expected cost of complying with current or reasonably anticipated future regional or federal greenhouse gas reduction requirements which are borne by generators and passed through in wholesale costs.

[3] For strategic electrification measures, the RI Test counts the incremental electric heating load as a negative benefit.
[4] The values for Rhode Island have also been included as Table E-9 in Appendix 5.
[5] Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short term fuel costs.

The avoided energy costs in the 2015 AESC Study Update are provided in four different costing periods consistent with ISO-NE definitions. Net energy savings are split up into these periods in the value calculation. The time periods are defined as follows:

- Winter Peak: October – May, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Winter Off-Peak: October – May; 11:00 p.m. – 7:00 a.m., weekdays. Also including all weekends and ISO defined holidays.
- Summer Peak: June – September, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Summer Off-Peak: June – September; 11:00 p.m. – 7:00 a.m., weekdays. Also including all weekends and ISO defined holidays.

In the benefits calculation, energy savings are grossed up using factors that represent transmission and distribution losses because a reduction in energy use at the customer means that amount of energy does not have to be generated, plus the extra generation that is needed to cover the losses that occur in the delivery of that energy is not needed.

Net energy savings for a program (or measures aggregated within a program) are allocated to each one of these time periods and multiplied by the appropriate avoided energy value.[6] The dollar benefits are then grossed up using the appropriate loss factors representing losses from the ISO delivery point to the end use customer.

- Summer Peak Energy Benefit ($) = kWh * $Energy\%_{SummerPk}$ * $SummerPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumPk\text{-}kWh}$)
- Summer OffPeak Energy Benefit ($) = kWh * $Energy\%_{SummerOffPk}$ * $SummerOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SummerOffPk\text{-}kWh}$)
- Winter Peak Energy Benefit ($) = kWh * $Energy\%_{WinterPk}$ * $WinterPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinterPk\text{-}kWh}$)
- Winter OffPeak Energy Benefit ($) = kWh * $Energy\%_{WinterOffPk}$ * $WinterOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinterOffPk\text{-}kWh}$)

[6] The notation "@Life" in the equation for value for this and other value components is an indication that the avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2018 dollars) of avoided costs for each year of the planning horizon from the base year over the life of the measure. For example, the avoided value component for a measure with an expected life of ten years for any given benefit component is the sum of the net present value of the annual avoided costs for that component in Year 1, Year 2, Year 3, etc., through Year 10.

2) Electric Generation Capacity Benefits

Avoided electric generation capacity values are appropriate for inclusion in the RI Test. When generators do not have to build new generation facilities or when construction can be deferred because of consumers' investments in energy efficiency, an avoided resource benefit is created. In the New England capacity market, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. The capacity requirement is based on load's contribution to the system peak, which, for ISO-NE, is the summer peak. Therefore, capacity benefits accrue only from summer peak demand reduction; there is currently no winter generation capacity benefit.

Demand savings created through program efforts are valued using the avoided capacity values from the 2015 AESC Study Update, Appendix B.[7] The values contained in the study reflect the avoided cost of peaking capacity, and incorporate a reserve margin and losses incurred from the generator to the point of delivery to the distribution companies. ISO-New England reserve margins are incorporated into the capacity values, since energy efficiency avoids the back-up reserves for that generation as well as the generation itself. A loss factor representing losses from the ISO delivery point to the end-use customer is used as a multiplier, since those losses are not included in the avoided costs. Demand savings are calculated to be coincident with the ISO-NE definition of peak.

The dollar value of benefits are therefore calculated as:

- Generation Capacity Benefit($) = kW_{Summer}*GenerationCapValue$/$kW_{(@Life)}$ * (1 + $\%Losses_{SummerkW}$)

3) Electric Transmission Capacity and Distribution Capacity Benefits

Avoided transmission and distribution capacity values are appropriate for inclusion in the RI Test. When transmission and distribution facilities do not have to be built or can be deferred because of lower loads as a result of consumers' investments in energy efficiency, an avoided resource benefit is created.

Electric transmission capacity and distribution capacity benefits are valued in the RI Test using avoided transmission and distribution capacity values calculated in a spreadsheet tool that was developed in 2005 by ICF International, Inc., the consultant that performed the biennial avoided cost study for New England's energy efficiency program administrators in that year. The tool calculates an annualized value of statewide avoided

[7] The values for Rhode Island have also been included as Table E-9 in Appendix 5

transmission and distribution capacity values from company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and Federal Energy Regulatory Commission (FERC) Form 1 accounting data.

Capacity loss factors are applied to the avoided T&D capacity costs to account for local transmission and distribution losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Thus, losses will be accounted for from the generator to the end use customer.

T&D benefits could be allocated to summer and winter periods, depending on the relation between summer and winter peaks on the local system. However, the Company's system is summer peaking. Therefore, the T&D benefits will be exclusively associated with summer demand reduction and the dollar value will be calculated as follows:

- Transmission Benefit ($) = ($kW_{Summer}$ * $Trans\$/kW_{(@Life)}$ * [1 + ($Losses_{SumkWTrans}$)]
- Distribution Benefit ($) = ($kW_{Summer}$ * $Dist\$/kWLife_{(@Life)}$ * [1 + ($Losses_{SumkWDist}$)]

4) Natural Gas Benefits

Avoided natural gas consumption is appropriate for inclusion in the RI Test. When a project in which consumers have invested saves natural gas, an avoided resource benefit is created.

Natural gas benefits in the RI Test will be valued using avoided natural gas values from the 2015 AESC Study Update, Appendix C.[8] These costs include commodity, transportation, and retail delivery charges that would be avoided by fuels not consumed by end users.

The AESC Study Report presents avoided natural gas value components into end-use categories to match with individual program characteristics. The natural gas categories are:

- Commercial and industrial, non-heating. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.
- Commercial and industrial, heating. Averages the monthly values for the months of November through March.

[8] The values for Rhode Island have also been included as Table G-9 in Appendix 5

- Residential heating. Averages the monthly values for the months of November through March. As these months have the highest natural gas values, by averaging over a fewer number of months, natural gas savings in this category typically have the highest value.
- Domestic hot water. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.

Using each of these end-use value components, the dollar value of fuel benefits is calculated as:

- Natural Gas Benefits ($) = MMBtu Gas Savings * (Gas$/MMBTU$_{(EndUseCategory,@Life)}$ +Greenhouse Gas $/MMBTU$_{(@Life)}$)

5) Delivered Fuel Benefits

Avoided delivered fuel costs (natural gas, propane, or fuel oil) are appropriate for inclusion in the RI Test. When a project in which consumers have invested saves fuel an avoided resource benefit is created.

Fuel benefits in the RI Test are valued using avoided fuel values from the 2015 AESC Study, Appendix D. The fuel oil categories are Residential #2, Commercial #2, Commercial #4, and Commercial and Industrial #6.

Using each of these end-use value components, the dollar value of fuel benefits is calculated as:

- Fuel Benefits ($) = MMBTU_Fuel Savings * Fuel$/MMBTU$_{(EndUseCategory,@Life)}$

6) Water and Sewer Benefits

Water savings created from program efforts should be valued and included in the RI Test. Water savings can be valued using avoided water and sewer values that are based on average water and sewer rates in Rhode Island. While there are no specific water efficiency measures, when a project in which consumers have invested to save electricity or fuel also affects water consumption—for example, a cooling tower project that reduces makeup water needed—a resource benefit is created. Depending on the project and metering configuration, changes in water consumption may also affect sewerage billings.

Water and sewerage rates were determined from an August 2014 internet survey of rates posted by the City of Providence[9] and the Narragansett Bay Commission[10].

Water and sewer benefits are counted for all projects, where appropriate, and calculated as follows:

- Water and Sewerage Benefits ($) = Water and/or Sewerage Savings * Water and/or Sewer $/Gal$_{(@Life)}$

7) Non-Energy Impacts

Other quantifiable non-resource or non-energy impacts may be created as a direct result of Least Cost Procurement efforts and, are therefore appropriate for inclusion in the RI Test. Non-energy impacts are typically associated with the number of measures installed, rather than the energy consumption of the equipment. They may be positive or negative. They may be one time benefits or recur annually. These effects will be included when they are a direct result of the measure and when they are quantifiable and avoidable.

The specific values of non-energy impacts used in the 2018 Annual Plan for prescriptive measures are documented in the 2018 RI Technical Reference Manual. Non-energy impacts may include – but are not limited to – labor, material, facility use, health and safety, materials handling, national security, property values, and transportation. For income-eligible measures, non-energy impacts also include the impacts of having lower energy bills to pay, such as reduced arrearages or avoided utility shut off costs. Non-energy impacts for Commercial and Industrial custom measures are counted when supported by site specific engineering calculations or other analyses.

The dollar value of non-resource benefits will be calculated as follows

- One-time Non-energy impacts ($) = Non-energy impact ($)/unit * Number of units
- Annual Non-energy impacts ($) = Non-energy impact ($)/unit * Number of units * Present Worth Factor$_{(@Life)}$

[9] Water Rates." Providence Water Supply Board. 2014.
<http://www.provwater.com/depts/cs/billrates.htm>
[10] "Rates." Narragansett Bay Commission. 2014.
<http://www.narrabay.com/en/Customer%20Service/Rates.aspx>

8) Price Effects

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. Consumers' investments in energy efficiency avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over a period of time, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of electricity. This is the observed in the New England market when ISO-New England activates its price response programs. When this price effect is a result of consumers' investments in energy efficiency, it is appropriate to include it in the RI Test.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms over all the kWh transacted in the market. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

DRIPE values developed for energy efficiency installations in 2017 from the 2015 AESC Study Update are used in the RI Test. The price effects are expressed as $/kWh for each of the four energy costing periods, $/kW for capacity, and $/MMBtu for natural gas. In addition, there are cross fuel effects that are counted for when natural gas energy efficiency affects the price of electricity. For example, homes and generators compete for natural gas in winter. Scarcity of natural gas for generation may drive up the cost of electricity. Therefore, reduction in natural gas consumption due to energy efficiency may cause a price effect for electricity. (Even though the price effect is in electricity, that DRIPE benefit is converted to $/MMBtu so that it can be attributed to the gas savings that create the effect.) The DRIPE benefit is calculated as:

- Summer Peak Energy DRIPE Benefit ($) = kWh * $Energy\%_{SumPk}$ * ($SummerPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{SummerPk\text{-}kWh}$)
- Summer OffPeak Energy DRIPE Benefit ($) = kWh * $Energy\%_{SumOffPk}$ * ($SumOffPkDRIPE\$/kWh_{(@Life}$ +$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{SummerOffPk\text{-}kWh}$)
- Winter Peak Energy DRIPE Benefit ($) = kWh * $Energy\%_{WinterPk}$ * ($WinterPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{WinterPk\text{-}kWh}$)
- Winter OffPeak Energy DRIPE Benefit ($) = kWh * $Energy\%_{WinOffPk}$ * ($WinterOffPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{WinterOffPk\text{-}kWh}$)

- Generation Capacity DRIPE Benefit($) = kW_{Summer} * CapDRIPEValue$/$kW_{(@Life)}$ * (1 + $\%Losses_{SummerkW}$)
- Natural Gas DRIPE Benefit ($) = MMBTU_Fuel Savings * (GasDRIPEValue$/$MMBTU_{(@Life)}$ +GasElectricDRIPE$/MMBtu)

9) CHP Benefits

CHP Benefits are assessed consistently with the RI Test and benefits described above. Additionally, R.I.Gen.Laws §39-1-27.7(c) (6) (iii) directs the Company to support the development of combined heat and power (CHP). The law requires that the following criteria be factored into the Company's CHP plan: (i) economic development benefits in Rhode Island; (ii) energy and cost savings for customers; (iii) energy supply costs; (iv) greenhouse gas emissions standards and air quality benefits; and (v) system reliability benefits. [11] Of these, energy and cost savings and energy supply costs are captured in the energy benefits described above. The other three benefits – economic development, greenhouse gas, and system reliability benefits – are described here.

Economic Development

For all CHP projects, net economic development benefits will be counted as benefits. The rate of economic development benefit will be $0.80 of lifetime gross state product increase per dollar of program investment, based on the report, "Macroeconomic Impacts of Rhode Island Energy Efficiency Investments: REMI Analysis of National Grid's Energy Efficiency Programs, prepare by National Grid in August 2014, as an update to the 2009 study "Energy Efficiency in Rhode Island: Engine of Economic Growth," prepared by Environment Northeast. The $0.80 multiplier reflects the present value of lifetime state gross domestic product (GDP) effects of program and participant spending that creates jobs in construction and other industries as the project is planned, and equipment is purchased and installed. Therefore, the CHP Economic Development benefits will be calculated as:

- Program and participant spending($) x $0.80

Greenhouse gas reduction benefits

For all CHP projects, greenhouse gas mitigation and air quality benefits will be counted as benefits to the extent they are not already captured in the BCR screening values and to the extent that usable emissions data is available. The emissions profile of the CHP site facility prior to the installation of the retrofit (most likely a combination of grid supplied generation for electricity and an on-site boiler for thermal needs) will be compared to the emissions post-retrofit (most likely the CHP unit alone). The change in

[11] See R.I. Gen.Laws § 39-1-27.7(c) (6) (iii).

emissions in tons will be multiplied by a value of $/ton for each pollutant and the values will be summed over all pollutants and counted as a benefit in the benefit/cost calculation. This method is contingent on having emissions data for all pollutants. This information is often difficult to come by; for example, ISO-New England annually publishes emissions per kWh for only SOx, NOx, and CO_2. Similarly, the amount of emissions for all pollutants associated with a particular CHP unit is not always provided.

Value from mitigation of CO_2 both embedded and non-embedded is already embedded in avoided energy costs in benefit-cost analysis.

System Reliability

If a CHP project is proposed in a system reliability target area, the system reliability benefits from deferring a distribution system upgrade would be captured in the System Reliability Procurement report. In the context of CHP located elsewhere in the state, system reliability benefits are the local distribution benefits created by the introduction of the CHP unit in the local area. Notably, CHP projects do not produce the same level of deferred distribution investment savings described in Section (3) above as traditional energy efficiency.[12] Accordingly, the distribution benefits are modified as follows:

- For CHP systems of less than 1 MW net capacity, the distribution deferral benefit value estimated by the Company based on system wide averages will be multiplied by 0.75 to incorporate an estimate of the reliability experience of discrete deployment of CHP units compared with end-use reduction efficiency measures which are spread across the state;[13]
- For CHP systems equal to or greater than 1 MW net capacity, the distribution benefit will consider location-specific distribution benefits, as opposed to average system-wide benefits. The results of this analysis will replace the

[12] With traditional energy efficiency projects, the installed measures permanently reduce load on the electric distribution system and, therefore, reduce the need to make distribution investments. CHP projects may not result in similar deferred distribution investment savings. A CHP unit may not be available at all peak times, and, absent any contractual or mechanical modification to ensure that the load does not reappear, the Company will still need to design and maintain the distribution system for when that unit goes off line during a peak hour on a peak day. This is particularly significant with larger CHP projects, in which a single host customer represents a significant percentage of the total load on a feeder. With multiple smaller units, some level of savings is possible, but these units are still not likely to produce distribution benefits in the same manner as traditional energy efficiency.

[13] As explained in footnote 12, *supra*, while multiple small CHP units may produce some level of savings, these units are still not likely to produce distribution benefits in the same manner as traditional energy efficiency. Therefore, the 0.75 factor is adopted as a planning assumption to represent the contingency that, when a single CHP unit on a feeder fails to perform, the load reappears on the system. As more CHP units, particularly smaller units, are deployed in the state, the diversity of operation may allow the adjustment factor to be increased. The Company intends to review this planning assumption based on actual experience for future EE Program Plan filings.

adjusted 0.75 of average system-wide distribution benefit described for CHP projects of less than 1 MW. This may entail a detailed engineering analysis performed by the Company, and additional costs. This consideration will have two parts: 1) identification of foreseeable investments that the CHP installation could potentially help defer, and their value; and 2) whether the unit will be sufficiently reliable, or firmed through the provision of physical assurance by the customer, to enable such savings to be realized;

- For CHP projects greater of 1 net MW or greater, gas system benefits not paid out as incentives to the Customer via the AGT incentive or gas service contract terms will be counted as benefits.[14]

10) Non-embedded Greenhouse Gas Reduction Benefits

In accordance with Section 1.2(B)(iii) of the Standards, the RI Test now includes the value of greenhouse gas (GHG) reductions not previously included in avoided energy costs. The value of these "non-embedded" GHG reductions was derived from the Avoided Energy Supply Costs in New England: 2015 Report (AESC Report).

The Resilient Rhode Island Act sets forth a carbon emission reduction goal of 80% below 1990 levels by 2050. The AESC Report determines that the marginal cost of stabilizing carbon dioxide (CO_2) emissions at 80% below 1990 levels by 2050 will be $100 per short ton. The report finds this cost is a "reasonable estimate of the societal cost of carbon emissions, and hence as the long-term value of the cost of reductions in carbon emissions required to achieve those targets".

In previous Plans, the Company incorporated the costs of CO_2 mitigation imposed and projected to be imposed by the Regional Greenhouse Gas Initiative (RGGI) and the costs associated with reasonably anticipated future federal greenhouse gas regulations in the avoided costs used in cost-effectiveness screening. The costs of compliance with RGGI and reasonably anticipated future federal regulations are one component of the $100 per short ton value. These costs are already included or "embedded" in the projected electric energy market prices. Therefore, the difference between the $100 per short ton societal cost and the regulatory compliance costs already embedded in the projected energy market prices represents the value of carbon emissions not included in the avoided energy costs.

[14] For example, a 3 MW installation with an additional sales volume of approximately 150,000 Dth per year would generate approximately $130,000 of marginal revenue per year under current rates. Assuming $100,000 of capital costs, the project could qualify for up to $573,000 in AGT funding, subject to budget limitations.

An example of this calculation for the year 2018 is shown below. The resulting $91.53 non-embedded avoided cost is applied as a benefit in the RI Test in that year.

- Societal Cost ($100) – Embedded Regulatory Compliance Cost ($8.47) = Non-Embedded Cost ($91.53)

The Company added the non-embedded CO_2 values from the following tables in the 2015 AESC report to the avoided costs used in the RI Test cost-effectiveness screening: Exhibit 4-5 for electric savings, Exhibit 4-14 for gas savings, and Exhibit 4-18 for oil savings.

The next revision to the AESC Report is due in 2018. The non-embedded value for New England's CO_2 emissions will be updated as part of this study and will be incorporated in the 2019 Annual Plan.

11) Economic Development Benefits (Non-CHP Measures)

In accordance with Section 1.2(B)(i) of the Standards, the RI Test now includes the application of multipliers for economic development impacts to all energy efficiency measures. This section details the methodology for applying economic benefits to non-CHP measures. Section number 9 in this document refers to the application of economic benefits to CHP measures.

The macroeconomic multipliers for the economic growth and job creation benefits of investing in cost-effective energy efficiency are derived from a recent study "Macroeconomic Impacts of Rhode Island Energy Efficiency Investments: REMI Analysis of National Grid's Energy Efficiency Programs", National Grid Customer Department, November, 2014.

The multipliers from the REMI analysis take into account how the energy efficiency programs impact Rhode Island's economy in three ways:

1. Program and participant spending represents a direct investment in Rhode Island energy efficiency infrastructure, creating jobs (construction impacts).
2. Bill savings to participants have positive economic impacts over the life of the energy efficiency measures, resulting in more spending on goods and services.
3. Rate increases and participant contributions to the cost of installing energy efficiency measures create short-term costs and reduce spending on goods and services.

It is likely that the benefit of bill savings to customers is already accounted for in cost-effectiveness screening since the value of all energy savings is included as a monetary benefit. In addition, the impact of customer costs is also already included as a negative dollar benefit. Therefore, to ensure no double counting of costs and benefits, only the multipliers associated with construction impacts should be included in the RI Test.

It is widely acknowledged that increased spending from installing energy efficiency measures creates jobs in the local economy. The Company, therefore, will apply the multipliers below to program and participant spending in its benefit-cost model. These multipliers are derived from Table 2 of the REMI analysis report.

GDP Multipliers for Construction Impacts		GDP/$ Spending	
		Electric	Natural Gas
Residential	Program Spending	0.71	0.71
	Participant Spending	0.75	0.75
Commercial	Program Spending	0.56	0.56
	Participant Spending	0.58	0.58

The Company finds that this application is a suitable first step in incorporating economic development impacts to the RI Test. The Company plans to commission an updated economic impact study during the 2018 program year to refine these assumptions for its 2019 Annual Plan.

12) Utility Costs

Utility costs incurred to achieve implementation of energy efficiency measures and programs are appropriate for inclusion in the RI Test. These costs have been categorized as follows:

- Program Planning and Administration (PP&A): These costs are the administrative costs associated with the utility role in program delivery, including payroll, information technology, contract administration, and overhead expenses.
- Marketing: These are the costs of marketing and advertising to promote a program. The costs also include the payroll and expenses to manage marketing.
- Rebates and Other Customer Incentives: These are the incentives from the programs to customers to move them to install energy efficient equipment. Incentives include, but are not limited to, rebates to customers, copayments to vendors for direct installation of measures, payments to distributors to buy down the cost of their products for sale in retail stores, payments to vendors to create and deliver information, the cost of an education course, or payments to lenders to buy down the interest in a loan. Customer incentives typically cover a portion of the equipment and installation costs directly associated with the energy efficient

equipment being installed.[15] For a retrofit project, the customer incentives cover a portion of the full cost of the efficiency project, as it is assumed that the alternative to the project is no customer action. For a failed equipment replacement/renovation/new construction project, these customer incentives cover a portion of the incremental additional costs associated with moving to a higher efficiency item or practice compared to what the customer would have done otherwise.

- Sales, Technical Assistance, and Training (STAT): These costs include the training and education of the trade ally community regarding the company's current energy efficiency programs. Examples of trade allies include but are not limited to: equipment vendors, heating contractors, lead vendors, project expediters, weatherization contractors, and equipment installers. These costs also include the tasks associated with internal and contractual delivery of programs. Tasks associated with this budget category include but are not limited to: lead intake, customer service, rebate application, quality assurance, technical assessments, engineering studies, plan reviews, payroll and expenses.
- Evaluation: These are the costs of evaluation or market research studies to support program direction and post-installation studies to study program effectiveness or verification of savings estimates. These costs also include the payroll and expenses to manage the research.
- Shareholder Incentive: This is the incentive received by the Company for meeting specified savings goals and/or performance targets; because the Company would not implement energy efficiency programs to the extent it does without the incentive, the shareholder incentive is included in the cost of energy efficiency.

13) Customer Costs

The customer's costs include their contribution to the installation cost of the efficient measure. Typically, this is the portion of the equipment and installation cost not covered by the customer incentive. As noted above, it excludes the cost of equipment that might be part of the customer's construction project, but that is not related to the energy efficiency portion of the project.

Benefit/Cost Calculations

[15] The full cost of the efficiency project is not necessarily the same thing as the full cost of the project being undertaken by the customer. For example, a customer may be renovating an HVAC system including installation of a new chiller and chilled water distribution. While the new distribution system may be part of the construction project, if it does not contribute to energy savings, it will not be included in the efficiency project cost; only the incremental cost of the new efficient chiller will be considered.

The cost effectiveness of a measure, program, or portfolio is simply the ratio of the net present value of the benefits to the net present value of the costs.

For the 2018 Annual Plan, all costs and benefits will be expressed in constant 2018 dollars. Where escalation of avoided costs or costs is needed to produce values in 2018 dollars, appropriate inflation rates are used.

The avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2018 dollars) of lifetime avoided costs for each year of the planning horizon from the base year up to the measure life of the equipment. Since all of the future year values are in constant 2018 dollars, lifetime benefits thus calculated are discounted back to mid-2018 using a real discount rate equal to [(1 + Nominal Discount Rate) / (1 + Inflation)] - 1.

As prescribed by the Standards, all values in the Plan and the benefit-cost model are stated in present value terms, "using a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a low-risk discount rate which would indicate that energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk". Specifically for the 2018 Annual Plan, the Company used a real discount rate of 0.27% equal to the twelve-month average of the historic yields from a ten-year United States Treasury note, using the 2016 calendar year to determine the twelve-month average.

The total benefits will equal the sum of the NPV of each benefit component:

[Energy Benefits + Generation Capacity Benefits + Avoided T&D Benefits + Natural Gas Benefits + Fuel Benefits + Water & Sewer Benefits + Non-Resource Benefits + Price Effects Benefits + Non-embedded Greenhouse Gas Reduction Benefits + Economic Development Benefits]

The total costs will equal the sum of the NPV of each cost component:

[Program Planning and Administration + Sales, Training, Technical assistance + Marketing + Rebates and Other Customer Incentives + Evaluation + Shareholder incentive+ Customer Cost]

The RI Test benefit/cost will then equal:

Total NPV Benefits/Total NPV Costs

Per the Standards, on a program level, all benefit categories are included in the benefit/cost calculation. All cost categories, except the shareholder incentive, are included at the program level because they are tracked at that level.[16]

On a sector level, the cost of pilots and educational/outreach programs which are not focused on producing savings and the projected shareholder incentive, are included with the other costs in the determination of cost effectiveness. The shareholder incentive is included at this level because it is designed to achieve savings targets by sector. At a portfolio level, the allocations to the Office of Energy Resources and EERMC are also included in the cost effectiveness calculation.

Separate calculations of benefits and cost-effectiveness are provided for the electric energy efficiency programs and natural gas energy efficiency programs. Some electric energy efficiency programs are expected to produce natural gas savings in addition to electricity savings while some natural gas energy efficiency programs are expected to produce electricity savings in addition to natural gas savings. All of the resource benefits produced by a program are shown with that program. For example, an HVAC project that improves air distribution incented through the electric Large C&I Retrofit Program will produce natural gas savings when natural gas is used by the participant for heating.

[16] Commitments, if any, of customer incentives made from one year to the next are excluded from the program costs used in the benefit/cost calculation. The costs are only counted in the year in which the incentive is paid and the savings are counted.

SC 2-9

Request:

Referring to Chapter 8 (Income Eligible) at page 154, Table 8-3, the BCA model assumes a value of $213,002 for Avoided Renewable Energy Certificate cost. Please provide the assumptions used by the Company to calculate this value, including solar output and market values for RECs over time. Please indicate whether the assumed market values for REC over time are consistent with the Company's plans for complying with the Renewable Energy Standard.

Response:

Please refer to the response to Division 1-1 and Attachment DIV 1-1-3 for the BCA.

Solar Output, in MWhrs, is captured on sheet "SOL – Benefits" - Row 36. These values are calculated using the proposal assumption of site capacity and utilizes the solar output prediction tool, "PVWatts".

Avoided REC Cost ($/MWh) is captured on sheet "SOL – Benefits" – Row 37. These values are taken from AESC (Avoid Energy Supply Component Study Group) 2015, updated in December 2016, and adjusted for inflation and wholesale risk premium.

The referenced information is reprinted below for convenience.

	Total Energy Output from Solar Generation (MW)	Avoided REC Cost ($/MWH)
Year 1	0.00	$ 6.12
Year 2	369.70	$ 6.76
Year 3	1109.11	$ 6.55
Year 4	3327.33	$ 8.02
Year 5	3327.33	$ 7.83
Year 6	3327.33	$ 7.43
Year 7	3327.33	$ 7.23
Year 8	3327.33	$ 6.90
Year 9	3327.33	$ 6.49
Year 10	3327.33	$ 6.09
Year 11	3327.33	$ 5.70
Year 12	3327.33	$ 6.30
Year 13	3327.33	$ 6.00
Year 14	3327.33	$ 6.12

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	Total Energy Output from Solar Generation (MW)	Avoided REC Cost ($/MWH)
Year 15	3327.33	$ 6.24
Year 16	3327.33	$ 6.36
Year 17	3327.33	$ 6.49
Year 18	3327.33	$ 6.62
Year 19	3327.33	$ 6.75
Year 20	3327.33	$ 6.89
Year 21	3327.33	$ 7.03
Year 22	3327.33	$ 7.17
Year 23	3327.33	$ 7.31
Year 24	3327.33	$ 7.46
Year 25	3327.33	$ 7.61
Year 26	3327.33	$ 7.76
Year 27	2957.63	$ 7.91
Year 28	2218.22	$ 8.07
Year 29	0.00	$ 8.23
Year 30	0.00	$ 8.40

Per R.I. Gen. Laws §39-26-6(g), "The commission shall annually make an adjustment to the minimum amounts required under the renewable energy standard under chapter 39-26 in an amount equal to the kilowatt hours generated by such units owned by the electric distribution company." Therefore, the renewable energy generated will impact the Company's RES; however, this impact and the benefits from it were conservatively not represented in either Societal or RIM BCA.

SC 2-10

Request:

Please identify the types of incentives the Company believes are most effective to induce consumers to purchase or lease an electric vehicle (EV). Please explain how the Company's proposals in the Electric Transportation Initiative would be effective in inducing consumers to purchase or lease EVs. Specifically identify any aspects of the Company's proposal that would address the barrier of high upfront costs associated with the purchase of EVs at this time.

Response:

The Company has not evaluated the effectiveness of different types of incentives to induce consumers to purchase or lease an electric vehicle (EV), but believes that (1) the impact of incentives and policy measures to promote EV adoption is greatest when multiple actions are taken in parallel, and (2) vehicle charging infrastructure is an important prerequisite for EV adoption.

As the Company stated in Schedule PST-1, Chapter 5 - Electric Transportation (Bates Page 110 of PST Book 1), the Company's initiative is structured as a three-year pilot to test multiple market development strategies. The Company will evaluate each part of the initiative and share these learnings with Rhode Island stakeholders and industry participants.

The purpose of the Company's proposal is not to reduce the upfront costs of EVs, but rather to complement other programs with that purpose, such as the Rhode Island Office of Energy Resources' purchase rebate and the federal EV tax credit. To address customers' concerns about the costs of electric vehicles at this time, the Company's Transportation Education and Outreach program will inform customers of available vehicle purchase or lease incentives from public sources and from manufacturers, operating cost savings available with EVs, ways to lower the cost of charging (such as the Company's proposed Off-Peak Charging Rebate Program), the growing number of EV models at mass market price points, and the increasing availability of lower-cost pre-owned EV.

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