2020 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.

The Company assessed the cost-effectiveness of the 2020 Annual Plan according to the Rhode Island Benefit Cost Test (RI Test) as approved by the PUC in Docket 4755 and in accordance with the Docket 4600 Benefit-Cost Framework.

The source for many of the avoided cost value components is “Avoided Energy Supply Components in New England: 2018 Report” (2018 AESC Study) prepared by Synapse Energy Economics for AESC 2018 Study Group, June 1, 2018.[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 2019 through 2021.

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,

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.

[1] The report is available online at: http://ma-eeac.org/studies/special-cross-sector-studies/

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.

<u>The Rhode Island Test Overview</u>

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
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) Non-embedded Greenhouse Gas Reduction Benefits
10) Economic Development Benefits
11) Non-embedded NOx Reduction Benefits
12) Value of Improved Reliability
13) Combined Heat and Power Benefits
14) Utility Costs
15) Participant Costs

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

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

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 2018 AESC Study, 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.

The avoided energy costs in the 2018 AESC Study 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

[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.

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 + $\%Losses_{WinterOffPk\text{-}kWh}$)

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 2018 AESC, 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

[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 2020 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.

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

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 + $\%Losses_{SummerkW}$)

In addition to the traditional valuation of electric generation capacity, for which results are provided in Appendix B, the 2018 AESC study developed a new approach to valuing the capacity of short duration measures that are not actively bid in the ISO-New England Forward Capacity Market (FCM). The AESC study has always provided avoided electric generation capacity values that are differentiated based on whether a measure is bid in the FCM (cleared capacity) or is not bid in the FCM and passively reduces system load and, as a result, reduces the ISO-NE load forecast and the resulting amount of capacity that is procured through the FCM (uncleared capacity), with the overall avoided capacity value representing a weighted average of the cleared capacity and uncleared capacity values. Given the three year forward nature of the FCM and the timing of the ISO-NE load forecast, it takes five years from the time of load reduction for uncleared capacity to begin impacting the FCM procurements. As a result, measures with a useful life less than five years (ex. demand response) would not produce any generation capacity benefits in years 1-5 under the traditional capacity modeling methodology.

The 2018 AESC study conducted a detailed analysis of the ISO-NE load forecast methodology and determined that there are deferred capacity benefits for short duration measures that are not bid in the FCM which persist beyond the useful measure life of the measure. The logic behind this analysis is that the ISO-NE load forecast utilizes multiple years of historical load data and that even a load reduction for only one year will have a lasting impact on the load forecast for a number of years. The deferred capacity valuation methodology for uncleared capacity is used to determine the avoided electric generation capacity value for demand response measures based on the values provided in Appendix J of the 2018 AESC study.

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 distribution capacity benefits are valued in the RI Test using avoided distribution capacity values calculated in a spreadsheet tool that was developed in 2005 by ICF International, Inc., updated with recommendations from the 2018 AESC Study. The tool calculates an annualized value of statewide avoided 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.

Electric transmission capacity benefits are valued in the RI Test based on the costs of Pool Transmission Facilities (PTF). The 2018 AESC study calculates an avoided cost for PTF of $94/kW-year in 2018 dollars. Based on recommendations from the 2018 AESC Study, the Company is using the PTF costs instead of local transmission investments.

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 2018 AESC Study, Appendix C. 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.
- 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 2018 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[8] and the Narragansett Bay Commission[9].

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 2020 Annual Plan for prescriptive measures are documented in the 2020 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

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

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

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 and kW 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 2020 from the 2018 AESC Study are used in the RI Test. The price effects are expressed as $/kWh for each of the four energy costing periods, $/kW for capacity, $/MMBtu for natural gas, and $/MMBtu for oil. There are also cross fuel effects that apply when natural gas energy efficiency affects the price of electricity due to the fact that residential heating and electric generation compete for natural gas supply in the winter. The resulting 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.) In addition, reducing demand for petroleum and refined products leads to a reduction in oil prices. 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$/MMBtu)
- Oil DRIPE Benefit ($) = MMBTU Fuel Savings * (OilDRIPEValue$/MMBTU$_{(@Life)}$)

9) Non-embedded Greenhouse Gas Reduction Benefits

In accordance with Section 1.2(B)(iii) of the Standards, the RI Test includes the value of non-embedded greenhouse gas (GHG) reductions.

The 2018 AESC Study developed two approaches for calculating non-embedded cost of carbon. The first approach is based on global marginal abatement costs that yield a value of $100 per short ton of CO_2 emissions and is identical to the prior 2015 AESC Study value used in the 2018 and 2019 Plans. The second approach is based on New England specific marginal abatement costs, where it is assumed that the marginal abatement technology is offshore wind. On October 24, 2018 an amendment to the 2018 AESC Study was issued that corrected assumptions related to the calculation of offshore wind costs. Based on this corrected projection of the future costs of offshore wind energy, the 2018 AESC Study amendment establishes a New England specific cost of $68 per short ton.

The Company proposes to apply the updated value of $68 per short ton in the RI Test as the estimate of the societal cost of carbon emissions, and as the long-term value of the cost to achieve the Resilient Rhode Island Act carbon emission reduction goal of 80% below 1990 levels by 2050. The Company is moving from the global to New England specific value as it represents a conservative and reasonable non-embedded carbon price that reflects the likely marginal abatement technology for Rhode Island in achieving its carbon reduction goals.

The costs of compliance with the Regional Greenhouse Gas Initiative (RGGI) are already included or “embedded” in the projected electric energy market prices. Therefore, the difference between the $68 per short ton societal cost and the RGGI compliance costs already embedded in the projected energy market prices represents the value of carbon emissions not included in the avoided energy costs.

An example of this calculation for the year 2020 is shown below. The resulting $56.86 non-embedded avoided cost is applied as a benefit in the RI Test in that year.

- Societal Cost ($68) – Embedded RGGI Compliance Cost ($11.14) = Non-Embedded Cost ($56.86)

The Company obtained the non-embedded CO_2 values from the following tables in the 2018 AESC Study for use in the RI Test cost-effectiveness screening: Table 154 for electric savings and Table 156 for gas savings and oil savings.

10) Economic Development Benefits (Non-CHP Measures)

In accordance with Section 1.2(B)(i) of the Standards, the RI Test 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 13 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 "Review of RI Test and Proposed Methodology" prepared for National Grid by the Brattle Group, January 31, 2019.

The Brattle Group study recommend the following key changes to the previous methodology used in "Macroeconomic Impacts of Rhode Island Energy Efficiency Investments, REMI Analysis of National Grid's Energy Efficiency Programs," National Grid Customer Department, November 2014, which developed the prior economic impact benefit multipliers for use in the RI Test:

1. The allocation of spending, benefits, and costs to sectors in REMI based on the breakdowns found in each program spending budget and projected benefits instead of the use of total overall Energy Efficiency Plan values. This provides for a program specific economic impact that more accurately reflects how the implementation of each program impacts the RI economy.
2. Changing the allocation of energy efficiency program spending to sectors in the REMI model from using a generic study to using actual electric and gas program budget data that more accurately reflects where money gets spent in the economy.

3. The exclusion of rebates and incentives for Residential Lighting, Home Energy Reports, HVAC, Residential Products, Residential New Construction (RNC) and Large Commercial New Construction from the REMI analysis.
4. Accounting for the negative impacts that reduced energy consumption has on transmission, distribution, and generation spending in Rhode Island.
5. Avoiding double counting of ratepayer benefits and costs in the RI Test by only counting their indirect and induced economic impacts.

These changes provide for a more accurate accounting of the net-incremental benefits of Rhode Island's energy efficiency programs beyond what is already claimed in the RI Test. The revised run of the REMI regional economic model of Rhode Island to estimate these economic impacts yielded the following program-specific multipliers for use in the RI Test.

Program Type	**GDP/$ Program Spending**
Electric Program	
Residential	
Residential New Construction (RNC)	$1.40
HVAC	$1.42
EnergyWise	$0.93
EnergyWise Multifamily	$1.34
Residential Lighting	$1.59
Residential Products	$1.52
Home Energy Reports	$1.00
Single Family - Income Eligible Services	$0.86
Income Eligible Multifamily	$1.19
Commercial and Industrial	
Large Commercial New Construction	$3.11
Large Commercial Retrofit	$5.80
Small Business Direct Install	$1.97
Total Electric Portfolio	**$2.14**

Gas Program	
Residential	
ENERGY STAR® HVAC	$0.83
EnergyWise	$1.01
EnergyWise Multifamily	$1.63
Home Energy Reports	$1.06
Residential New Construction	$0.22
Single Family - Income Eligible Services	$0.99
Income Eligible Multifamily	$1.55
Commercial and Industrial	
Large Commercial New Construction	$1.42
Large Commercial Retrofit	$2.53
Small Business Direct Install	$1.75
Commercial & Industrial Multifamily	$1.89
Total Gas Portfolio	**$1.26**

Demand Response	
Residential Connected Solutions	$0.83
Commercial Connected Solutions	$2.19
Total Demand Response Portfolio	**$2.02**

The Company will apply the updated multipliers at the program level as part of the RI Test.

11) Non-embedded NOx Reduction Benefits

In accordance with Section 1.2(B)(iii) of the Standards and the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of nitrogen oxides (NO_x) emission reductions not already embedded in the avoided cost of energy.

NO_x emissions come from a variety of sources including industrial processes and the combustion of natural gas for electric generation and heating systems. NO_x contributes to the formation of fine particles (PM) and ground level ozone that are associated with adverse health effects including respiratory illness. When a consumer installs an energy efficiency measure that reduces electric generation and natural gas usage, and thus NO_x emissions, an avoided resource benefit is created.

The 2018 AESC Study utilizes published averages for the continental United States to develop a non-location specific, non-embedded NO_X emission cost of $31,000 per ton of nitrogen, which translates into an avoided wholesale cost for NO_X of $1.65 per MWh.

The Company obtained the non-embedded NO_X values from the following tables in the 2018 AESC Study: Table 157 for electricity and Table 158 for non-electric fuels.

12) Value of Improved Reliability

In accordance with the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of improved reliability from energy efficiency investments.

The 2018 AESC Study used the following methodology to determine the value of improved reliability. The study used the value of lost load (VoLL) from the Lawrence Berkeley National Laboratories (LBNL) assessment "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Berkeley: LBNL, 2015. LBNL-6941E. The VoLL describes the cost to consumers of being unable to take power from the system. The AESC 2018 Study then applied customer segment ratios typical to New England to adjust the LBNL findings to be suitable for the region. The resulting value is $37/kWh. The study also computed an estimate of the value of reliability as the ratio of annual state Gross Domestic Product (GDP) to annual energy consumption which results in a lower bound of $12/kWh.

The 2018 AESC Study then examined the effect of load reduction's ability to increase reserve margins in the ISO New England (ISO-NE) Forward Capacity Market (FCM) and therefore increase reliability in the wholesale generation market.

Load reductions can improve generation reserves in the following ways:

1. To the extent that energy efficiency reduces the capacity clearing price in ISO-NE FCM auctions, the amount of capacity acquired will increase, leading to higher reserve margins and therefore increased reliability.
2. Lower capacity market prices will result in some additional supply resources not clearing in the FCM auction. Some of those resources will continue to operate and provide generation when supply is tight and prices are high.
3. The ISO-NE Competitive Auctions with Sponsored Policy Resources (CASPR) program will result in some resources supported by state mandates being excluded from participating in the FCM auctions. With lower load, these non-cleared capacity resources will create a contribution to reserves and reliability.
4. Some energy efficiency measures that reduce load do so without impacting the amount of cleared capacity in the FCM such as measures in behavior based

programs and demand response programs not bid into the market. These load reductions will increase the reserve marking and therefore improve reliability.

The ISO-NE marginal reliability index (MRI) estimates values from the above impacts of load reduction. The MRI is the change in loss of energy expectation (LOEE) in MWh, for each additional MW of available capacity or reserve margin. The 2018 AESC Study calculated the final values per kW-month for increased reserve capacity, by multiplying the two estimates of the VoLL by the FCM Auction 12 MRIs at various clearing prices, with the corresponding reserve margins.

As recommended by the AESC 2018 Study, the Company applies different reliability values to measures that clear and don't clear the Forward Capacity Market auction. This is due to the fact that the reliability effect of cleared energy efficiency load reductions will be partially offset by reduction in the amount of other capacity cleared, while uncleared load reductions will not be subject to such offsets.

The Company applied Reliability Value of Cleared EE ($/kW-year) from AESC 2018 Study to all summer kW savings associated with cleared measures and the Reliability Value of Uncleared EE ($/kW-year) from Table 99 to all summer kW savings associated with uncleared measures.

The reliability benefit is calculated as follows with the ReliabilityValue$/kW changing whether a measure is assumed to be cleared or uncleared in the FCM auction. The 2018 AESC Study finds that the 15-year levelized benefit of increasing generation reserves through reduced energy usage is $0.65/kW-year for cleared resources and $6.60/kW-year for uncleared load reductions.

- Wholesale Reliability Value Benefit ($) = kWSummer * ReliabilityValue$/kW(@Life) * (1 + %LossesSummerkW)

13) Combined Heat and Power Benefits Benefits

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.[10] Of these, energy and cost savings and energy supply costs are captured in the energy benefits

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

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 $2.13 of lifetime gross state product increase per dollar of program investment for CHP projects less than 3 MW in size, based on the report, "Review of RI Test and Proposed Methodology" prepared for National Grid by the Brattle Group, January 31, 2019. The $2.13 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 $2.13

For CHP projects larger than 3 MW in size, the Company will run a REMI analysis using project-specific values in accordance with the recommended methodology from the Brattle Group study.[11]

Greenhouse gas emissions standards and air quality 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 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. Where locational information is not available,

11 In the 2020 Benefit Cost Model, the Company applied a weighted average economic multiplier to the C&I Retrofit program that accounts for the economic multipliers for C&I Retrofit and CHP. CHP expenditures, besides incentives, are not disaggregated from the rest of the expenditures on the C&I Retrofit program so the multiplier cannot be applied directly to program spending for CHPs. Therefore, the Company created a multiplier applicable to both CHP and C&I Retrofit by taking a weighted average of the two multipliers, weighted by incentives to be spent on CHP and the rest of C&I Retrofit projects. The final weighted average multiplier applied to the total C&I Retrofit program, including CHP, was $5.70.

the value of CO_2 emission reductions and NOx reductions will be calculated consistent with sections 9 and 11 above.

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 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;

[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 11, *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.

- For CHP projects 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]

14) 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,

[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.

[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.

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.

15) 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

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 2020 Annual Plan, all costs and benefits will be expressed in constant 2020 dollars. Where escalation of avoided costs or costs is needed to produce values in 2020 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 2020 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 2020 dollars, lifetime benefits thus calculated are discounted back to mid-2020 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 2020 Annual Plan, the Company used a real discount rate of 0.84% equal to the twelve-month average of the historic yields from a ten-year United States Treasury note, using the 2018 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 + Non-embedded NOx Reduction Benefits + Value of Improved Reliability]

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

[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.

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.