

2024 Rhode Island Test Description

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1 Introduction

This section has been prepared pursuant to Section 1.3(C) and 3.2(N) of the Least Cost Procurement Standards as approved and adopted pursuant to Rhode Island PUC Docket 23-07-EE¹ (referred to herein as the “LCP Standards”), and in alignment with the Rhode Island Benefit Cost Test (RI Test) as defined by the Standards and the Docket 4600A Benefit-Cost Framework and associated Guidance. The methods identified herein will be used for the calculation of benefits and costs associated with the 2024 Annual Energy Efficiency Plan.

Two key supporting documents for cost-effectiveness are the Technical Reference Manual (TRM) and the Avoided Cost Study. For the Annual Plan, the Company developed the 2024 Rhode Island Technical Reference Manual, which documents the savings / savings algorithms and costs for proposed 2024 measures. The TRM identifies the sources for the savings estimates. Sources can be evaluation studies, engineering analyses, and/or other research. The TRM is a public document and was provided to the EERMC and its consultants to support and facilitate their determination of the Plan’s cost-effectiveness. The TRM is reviewed and updated annually to reflect changes in technology, baselines, and evaluation results.

The cost-effectiveness analyses of the proposed programs use avoided energy supply costs developed by Synapse Energy Economics as part of the “Avoided Energy Supply Components in New England: 2021 Report” (2021 AESC Study). The study is sponsored by the New England electric and gas efficiency program administrators and is used for cost-effectiveness screening in 2021 or later. The avoided costs reflect a view of market conditions over the full study horizon (2021-2036) at the time of the study² and are highly influenced by the cost of fossil fuels and expectations about ISO-NE’s forward capacity market. Company-specific transmission and distribution capacity values are also included. The 2021 AESC Study introduced four counterfactual scenarios representing variations in demand-side measures offered in the future. For cost-effectiveness screening of the 2024 Rhode Island energy efficiency portfolio, the Company used Counterfactual #4 as the best representative scenario for future DSM portfolios. Counterfactual #4 models a scenario in which program administrators install no new energy efficiency resources in 2021 or later years. This scenario includes some amount of assumed building electrification but does not include any installed active demand management resources.³

¹ https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-07/2307-LCP%20Standards_final.pdf

² The long-term view is appropriate for energy efficiency planning, as most measures have expected useful lifetimes in excess of 10 years. Fuel cost increases experienced since the study was completed are not reflected in the avoided costs but in the past such price spikes have tended to dissipate over time.

³ Refer to the 2021 AESC Executive Summary for a descriptions of Counterfactuals #1 – 4 https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

2 The RI Test Overview and Docket 4600 Benefit Cost Framework

The RI Test compares the present value of net benefits associated with the lifetime net savings of an energy efficiency measure / program to the total costs necessary to implement that measure / program. The RI Test may be applied to any energy efficiency measure / program independent of primary fuel type.

The RI Test captures the value created by efficiency measures installed in a particular program year across 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, a measure's benefits are present-valued so that costs and benefits may be compared.

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

RI Test costs are defined as expenses paid by both the utility and by participants plus the increase in supply costs for any period in which 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 (i.e., outside of the program), 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 customers accept program funds to implement an energy efficiency measure they would have installed anyway, the associated savings are known as “free-ridership.” From the perspective of resource acquisition through utility programs, it is important to distinguish whether a customer would have implemented the efficiency measure without the program. Therefore, savings associated with free ridership are deducted from program savings.⁴ The cumulative impact of realization rates and market effects on gross savings is known as net savings.

⁴ Both free-ridership and spillover have been determined from evaluation, measurement, and verification studies of program participants, non-participants, and other market actors, such as developers and vendors.

The primary assessment of cost-effectiveness in the RI Test captures all benefits and costs shared between Rhode Island and other jurisdictions. Modifications made to the LCP Standards in 2023 specify an additional assessment of cost-effectiveness including only those benefits and costs that will be allocated to Rhode Island Energy. The Company has determined that pool transmission capacity benefits (described in Section 3.3) and rest-of-pool DRIPE (section 3.8) accrue out of state; these are excluded from a secondary assessment of cost-effectiveness in Attachments 5 and 6. To the best of the Company's knowledge, no costs accrue out of state.

The benefits and costs considered in the RI Test as applied to Energy Efficiency are detailed in the next section.

3 Description of Program Benefits and Costs

The following benefits and costs are quantified and monetized in the RI Test.⁵ Section 5 of this attachment shows the alignment of each benefit and cost category to the Docket 4600 Benefit-Cost Matrix for the electric portfolio.

Benefits

- Electric Energy Benefits
- Electric Generation Capacity Benefits
- Electric Transmission Capacity and Distribution Capacity Benefits
- Natural Gas Benefits
- Fuel Benefits (including the value of delivered fuel savings from programs that influence delivered fuel consumption)
- Water and Sewer Benefits
- Non-Energy impacts
- Demand Reduction Induced Price Effects (DRIPE)
- Non-embedded Greenhouse Gas Reduction Benefits
- Non-embedded NOx Reduction Benefits
- Value of Improved Reliability
- Combined Heat and Power Benefits

Costs

- Utility Costs
- Participant Costs

⁵ Economic Development Benefits are a recognized benefit in Rhode Island. Their monetized value, however, is not included in the RI Test calculation but is reported separately.

3.1 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.

Electric energy savings are valued using the avoided electric energy costs developed in the 2021 AESC Study, Appendix B. The values in the 2021 AESC Study represent wholesale electric energy commodity costs that are avoided when generators produce less electricity because of energy efficiency.⁶ These values include pool transmission losses incurred from the generator through the point of delivery / the distribution company, and the costs of renewable energy credits borne by generators. 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 2021 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 includes 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 includes all weekends and ISO defined holidays.

In the calculation of benefits, energy savings are grossed up using factors that represent transmission and distribution losses, because a reduction in energy use at the customer site means less energy needs to be generated and less extra generation is needed to cover losses that occur in delivery. A wholesale risk premium factor is also added to capture market risk factors typically recovered by generators in their pricing, which also increases the wholesale costs.

⁶ 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. Avoided costs 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.

Net energy savings for a program (or measures aggregated within a program) are allocated to each costing period and multiplied by the appropriate avoided energy value.⁷ 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_{SummerPk-kWh}) * (1 + Wholesale Risk Premium)
- Summer OffPeak Energy Benefit (\$) = kWh * Energy%_{SummerOffPk} * SummerOffPk\$/kWh_(@Life) * (1 + %Losses_{SummerOffPk-kWh}) * (1 + Wholesale Risk Premium)
- Winter Peak Energy Benefit (\$) = kWh * Energy%_{WinterPk} * WinterPk\$/kWh_(@Life) * (1 + %Losses_{WinterPk-kWh}) * (1 + Wholesale Risk Premium)
- Winter OffPeak Energy Benefit (\$) = kWh * Energy%_{WinterOffPk} * WinterOffPk\$/kWh_(@Life) * (1 + %Losses_{WinterOffPk-kWh}) * (1 + Wholesale Risk Premium)

3.2 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 facilities or when construction can be deferred because of 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 the 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 2021 AESC Study, Appendix B. The values contained in the study reflect the avoided cost of peaking capacity and incorporate a reserve margin and losses incurred from the generator through the point of delivery and the distribution companies. ISO-NE 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.

⁷ The notation "@Life" 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 2023 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.

The dollar value of benefits is therefore calculated as:

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

In addition to the traditional valuation of electric generation capacity, for which results are provided in Appendix B, the 2021 AESC study also valued the capacity of short duration measures that are not actively bid in the ISO-NE 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 into the FCM or not.⁸ 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 would not produce any generation capacity benefits in years 1-5 under the traditional capacity modeling methodology.

The 2021 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 measure's useful life. The logic behind this analysis is that the ISO-NE load forecast utilizes multiple years of historical load data, and even a load reduction for only one year will have a lasting impact on the load forecast for several years. The deferred capacity valuation methodology for uncleared capacity is used to determine the avoided electric generation capacity value for these measures based on the values provided in Appendix J of the 2021 AESC study.

3.3 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 because 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 originally developed in 2005 by ICF International, Inc., updated with recommendations from recent AESC Studies. The ICF 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. The calculations of the electric distribution capacity benefits were updated for the 2024 plan using updated inputs to this tool and results in an avoided distribution capacity cost of \$174.41/kW-year in 2023 dollars.

⁸ Capacity bid into the FCM is known as cleared capacity. Capacity not bid into the FCM is known as uncleared capacity. Uncleared capacity passively reduces system load and subsequently reduces the ISO-NE load forecast and the resulting amount of capacity that is procured through the FCM.

Electric transmission capacity benefits are valued in the RI Test based on the costs of Pool Transmission Facilities (PTF). The 2021 AESC study calculates an avoided cost for PTF of \$97.46/kW-year in 2021 dollars. In the 2021 AESC Study the estimation of the PTF values was revised to include transmission projects anticipated to occur through 2026. The Company continues to use the avoided PTF values instead of the avoided cost of local transmission investments in screening the energy efficiency portfolios. PTF values are sourced from Appendix B.

The Company has also developed an estimate of non-PTF capacity value. This estimate was developed using the ICF model using company-specific information on load growth and investments in non-PTF transmission. The Company has calculated the value of the avoided cost for non-PTF of \$11.89/kW-year in 2023 dollars.

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 (\$) = $(kW_{\text{Summer}} * \text{Trans}\$/kW_{(\text{@Life})} * [1 + (\text{Losses}_{\text{SumkWTrans}})])$ where $\text{Trans}\$/kW$ is the sum of PTF and non-PTF transmission avoided costs.
- Distribution Benefit (\$) = $(kW_{\text{Summer}} * \text{Dist}\$/kW_{(\text{@Life})} * [1 + (\text{Losses}_{\text{SumkWDist}})])$

3.4 Natural Gas Benefits

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

Natural gas benefits in the RI Test are valued using avoided natural gas values from the 2021 AESC Study, Appendix C. These costs include commodity costs, pipeline transportation costs, and retail distribution margin costs / delivery charges that would be avoided by fuels not consumed by end users.

The 2021 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/hot water

- Assumes savings are constant throughout the year.
- Averages monthly natural gas values over 12 months.
- Commercial and industrial, heating
 - Averages the monthly values for November through March.
- Residential heating
 - Averages the monthly values for November through March. These months have the highest natural gas values. Therefore, associated natural gas savings are comparatively high, despite the exclusion of monthly values for April through October.
- Residential water heating/residential non-heating
 - Assumes savings are constant throughout the year.
 - Averages monthly natural gas values over 12 months.
- All commercial and industrial
 - Used for behavioral savings, codes and standards, and custom measures.
- All residential
 - Used for behavioral programs.
- All retail end-uses

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

- Natural Gas Benefits (\$) = MMBtu Gas Savings * (Gas\$/MMBtu_(EndUseCategory,@Life))

3.5 Delivered Fuel Benefits

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

Fuel benefits in the RI Test are valued using avoided fuel values from the 2021 AESC Study, Appendix D. The 2021 AESC Study developed estimates of avoided fuel costs for residential distillate fuel oil, commercial distillate fuel oil, commercial residual fuel oil, industrial distillate fuel oil, industrial residual fuel oil, and residential propane.

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

- Fuel Benefits (\$) = MMBtu_Fuel Savings * Fuel\$/MMBtu_(EndUseCategory,@Life)

3.6 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 an electricity or fuel efficiency project 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 a May 2021 internet survey of rates posted to the Rhode Island PUC website, updated as of September 3, 2020. Average rates were calculated for both residential and commercial and industrial customers and applied as appropriate to the water savings generated by measures.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)

3.7 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. However, in some cases these impacts are applied on an annual or one-time basis. These impacts may be positive or negative, and they may be one-time benefits or annually recurring. The effects of non-energy impacts will be included when they are a direct result of the measure and are quantifiable and avoidable.

The specific values of non-energy impacts used in the 2024 Annual Plan for prescriptive measures are documented in the 2024 RI Technical Reference Manual. Non-energy impacts may include – but are not limited to – labor, material, facility use, health and safety, materials handling, 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.

⁹ RI Regulated Water Suppliers – Rates Updated September 3, 2020,
<http://www.ripuc.ri.gov/utilityinfo/water/residentialgri.html>

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)

3.8 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 time, the market adjusts to lower demand. However, until the market adjustment, reduced demand leads to a reduction in the market price of electricity. This trend is observed in the New England market when ISO-NE activates its price response programs. When this price effect results from consumer investments in energy efficiency, it is appropriate to include the effect in the RI Test.

DRIPE effects are very small when expressed as an impact on market prices, i.e., reductions of a fraction of a percent. However, 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 to large absolute dollar amounts.

DRIPE values developed for energy efficiency installations in 2024 from the 2021 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. For the electric energy DRIPE, there are values for in-state as well as rest-of-pool DRIPE. There are also cross fuel effects that apply when natural gas energy efficiency affects the price of electricity because 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.¹⁰ In addition, reducing demand for petroleum and refined products leads to a reduction in oil prices. The DRIPE benefit is calculated as:

¹⁰ Even though the price effect is for electricity, that DRIPE benefit is converted to \$/MMBtu so that it can be attributed to the gas savings that create the effect.

- Summer Peak Energy DRIPE Benefit (\$) = kWh * Energy%_{SumPk} * (SummerPkDRIPE\$/kWh_(@Life+ElectricGasDRIPE\$/kWh) * (1 + %Losses_{SummerPk-kWh}) * (1 + Wholesale Risk Premium)
- Summer OffPeak Energy DRIPE Benefit (\$) = kWh * Energy%_{SumOffPk} * (SumOffPkDRIPE\$/kWh_(@Life+ElectricGasDRIPE\$/kWh) * (1 + %Losses_{SummerOffPk-kWh}) * (1 + Wholesale Risk Premium)
- Winter Peak Energy DRIPE Benefit (\$) = kWh * Energy%_{WinterPk} * (WinterPkDRIPE\$/kWh_(@Life+ElectricGasDRIPE\$/kWh) * (1 + %Losses_{WinterPk-kWh}) * (1 + Wholesale Risk Premium)
- Winter OffPeak Energy DRIPE Benefit (\$) = kWh * Energy%_{WinOffPk} * (WinterOffPkDRIPE\$/kWh_(@Life+ElectricGasDRIPE\$/kWh) * (1 + %Losses_{WinterOffPk-kWh}) * (1 + Wholesale Risk Premium)
- Generation Capacity DRIPE Benefit (\$) = kW_{Summer} * CapDRIPEValue\$/kW_(@Life) * (1 + %Losses_{SummerkW}) * (1 + Wholesale Risk Premium)
- Natural Gas DRIPE Benefit (\$) = MMBtu_Fuel Savings * (GasDRIPEValue\$/MMBtu_(@Life) + GasElectricDRIPE\$/MMBtu)
- Oil DRIPE Benefit (\$) = MMBtu Fuel Savings * (OilDRIPEValue\$/MMBtu_(@Life))

3.9 Non-embedded Greenhouse Gas Reduction Benefits

In accordance with Section 1.3(C)(iv) of the LCP Standards and the Docket 4600 Benefit-Cost Framework the RI Test includes the value of non-embedded greenhouse gas (GHG) reductions.

The 2021 AESC Study developed multiple approaches for calculating the non-embedded cost of carbon.¹¹ The four methods for calculating the non-embedded cost of carbon are:

- A damage cost approximated by the social cost of carbon (SCC);
- A global marginal abatement cost (MAC) approach;
- An approach based on New England MAC (electric sector), assuming a cost derived from electric sector technologies, with offshore wind being the marginal abatement technology; and
- An approach based on New England MAC (multiple sector), assuming a cost derived across multiple sectors (i.e., renewable natural gas).

For the 2024 Annual Plan, the Company uses the New England MAC (electric sector) values. The Company is actively involved in the Executive Climate Change Coordinating Council (EC4) process and, in future plans, will use updated values that result from that process when they are available.

¹¹ The 2021 AESC Study, re-released on May 14th, 2021, may be found at the following: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

The AESC 2021 Supplemental Study found that the SCC was \$393/short ton, levelized over a 15-year period, and the May re-release of the 2021 AESC study found that the New England MAC (electric sector) was \$124/short ton, levelized over a 15-year period, both values being in 2021 dollars.¹²

The costs of compliance with the Regional Greenhouse Gas Initiative (RGGI) are already included or “embedded” in the projected electric energy market prices. Therefore, in the context of electric savings, these costs are removed from the overall cost of carbon to obtain the non-embedded cost of carbon. In the context of fossil fuel savings, which are not affected by the cost of compliance with RGGI, the full value of the cost of carbon may be used as the non-embedded cost of carbon. The 2021 AESC study found that the embedded cost of RGGI was \$8.50/short ton, levelized over a 15-year period (in 2021 dollars). As a result, the non-embedded costs of carbon under the New England MAC (electric sector) and SCC GHG cost basis are approximately \$115/ton and \$385/ton, respectively.

The Company obtained the non-embedded cost of carbon values from User Interface file Appendix B of the 2021 AESC Study for electric savings and User Interface file Appendix G for gas, oil, and propane savings.¹³ In this form, the non-embedded cost of carbon is expressed as a \$/kWh value or a \$/MMBtu value, the former of which depends on the summer/winter peak/off-peak short tons/kWh of electricity from a Synapse-modeled electric grid (EnCompass model, Counterfactual #1) through time and the latter of which depends on whether the MMBtu savings come from natural gas, oil, and propane given constant emission factors as reported by the U.S. Energy Information Agency.¹⁴ Fossil fuel emission factors are as follows:

- Natural Gas emission factor: 0.0585 short tons/MMBtu
- Fuel Oil emission factor: 0.0805 short tons/MMBtu
- Propane emission factor: 0.0695 short tons/MMBtu

The non-embedded greenhouse gas reduction benefit is calculated by multiplying the kWh and/or MMBtu fuel savings by the respective non-embedded cost of carbon specific to that fuel type and temporal category, if applicable (e.g., summer peak). The “NonEmbeddedCarbonValue\$” portion of the calculations depends further on SCC or New England MAC (electric sector) applicability for each measure.

¹² Because of the long-term nature of climate impacts, the Supplemental Study uses longer term discount rates in the derivation of these values than those used in AESC 2021.

¹³ In order to obtain the non-embedded CO₂ values based on Synapse’s updated guidance for SCC, values from Table 1 of the AESC 2021 Supplemental Study were placed into Table 16 of the “Library” tab under the “1.00%” discount rate column in the User Interface file. Toggling for “Social cost of CO₂” or “New England MAC (electric sector)” in cell D24 of the “User Interface” tab directly impacts which non-embedded cost of carbon is output in Appendix B and G. The workbook must be set to “Automatic” calculation mode for proper calculation.

¹⁴ While Counterfactual #4 is used as the basis of RI’s avoided costs, the User Interface workbook is designed to use Counterfactual #1 for calculating CO₂ short tons/MWh from the modeled electric grid. The workbook states “All counterfactuals are expected to have largely similar marginal emission rates.”

- Summer Peak Non-Embedded Greenhouse Gas Benefit (\$) = kWh * Energy%_{SummerPk} * SummerPkNonEmbeddedCarbonValue\$/kWh_(@Life) * (1 + %Losses_{SummerPk-kWh})
- Summer OffPeak Non-Embedded Greenhouse Gas Benefit (\$) = kWh * Energy%_{SummerOffPk} * SummerOffPkNonEmbeddedCarbonValue\$/kWh_(@Life) * (1 + %Losses_{SummerOffPk-kWh})
- Winter Peak Non-Embedded Greenhouse Gas Benefit (\$) = kWh * Energy%_{WinterPk} * WinterPkNonEmbeddedCarbonValue\$/kWh_(@Life) * (1 + %Losses_{WinterPk-kWh})
- Winter OffPeak Non-Embedded Greenhouse Gas Benefit (\$) = kWh * Energy%_{WinterOffPk} * WinterOffPkNonEmbeddedCarbonValue\$/kWh_(@Life) * (1 + %Losses_{WinterOffPk-kWh})
- Natural Gas Non-Embedded Greenhouse Gas Benefit (\$) = MMBtu Gas Savings * GasNonEmbeddedCarbonValue\$/MMBtu_(Gas, @Life)
- Fuel Oil Non-Embedded Greenhouse Gas Benefits (\$) = MMBtu Fuel Oil Savings * FuelOilNonEmbeddedCarbonValue\$/MMBtu_(Fuel Oil, @Life)
- Propane Non-Embedded Greenhouse Gas Benefits (\$) = MMBtu Propane Savings * PropaneNonEmbeddedCarbon\$/MMBtu_(Propane, @Life)

To quantify the Year 1 gross carbon reduction due to the 2024 Annual Plan, the relevant emission factors (short tons/MWh or short tons/MMBtu_{Fuel}) are multiplied by the relevant gross annual savings. For the electricity emission factor, the value used reflects an average across the summer/winter peak/off-peak values found in the AESC 2021 study for the Plan year in question. For the 2024 Annual Plan, the Year 1 electricity emission factor is found to be 0.39413 short tons/MWh in 2024.

Contribution to Rhode Island's emission reduction targets may be quantified by dividing the total Year 1 gross carbon reduction due to the 2024 Annual Plan by the % reduction of Rhode Island's 1990 Annual Gross GHG Inventory for the interim goal of interest.¹⁵ This relationship can be described as follows:

- Year 1 Gross Carbon Reduction as % Progress Toward X Interim Goal = (Year 1 Gross Carbon Reduction) / [(% Reduction of Rhode Island's 1990 Gross GHG Inventory by X Year) * (Rhode Island's 1990 Gross GHG Inventory)]

¹⁵ Rhode Island's Greenhouse Gas Emissions Inventory between 1990 and 2018 may be found at the following: <https://dem.ri.gov/programs/air/ghg-emissions-inventory.php>

3.10 Non-embedded NO_x Reduction Benefits

In accordance with Section 1.3(C)(iv) 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 subsequently NO_x emissions), an avoided resource benefit is created.

The 2021 AESC Study utilizes published averages for the continental United States to develop a non-location specific, non-embedded NO_x emission cost. The 2021 AESC Study assumes a 90/10 mix of NO and NO₂, which translates to a price of \$14,700 per short ton of NO_x at the median value from cited studies. That translates to an avoided cost for NO_x equal to \$0.77 per MWh.

The Company obtained the non-embedded NO_x values from Appendix B in the User Interface file for Counterfactual #4 for electricity savings and Appendix G in the User Interface file for non-electric savings.

The non-embedded NO_x reduction benefit is calculated similarly to the non-embedded greenhouse gas reduction benefit except that natural gas and fuel oil are sector specific. In other words, Appendix G of the User Interface tool provides non-embedded NO_x costs for natural gas and fuel oil depending on whether those savings are derived from the residential, commercial, or industrial sector. The non-embedded NO_x reduction benefit is calculated by multiplying the kWh and/or MMBtu fuel savings by the respective non-embedded cost of NO_x specific to that fuel type, sector, and temporal category (e.g., summer peak), if applicable.

- Summer Peak Non-Embedded NO_x Benefit (\$) = kWh * Energy%_{SummerPk} * SummerPkNonEmbeddedNOxValue\$/kWh_(@Life) * (1 + %Losses_{SumPk-kWh})
- Summer OffPeak Non-Embedded NO_x Benefit (\$) = kWh * Energy%_{SummerOffPk} * SummerOffPkNonEmbeddedNOxValue\$/kWh_(@Life) * (1 + %Losses_{SummerOffPk-kWh})
- Winter Peak Non-Embedded NO_x Benefit (\$) = kWh * Energy%_{WinterPk} * WinterPkNonEmbeddedNOxValue\$/kWh_(@Life) * (1 + %Losses_{WinterPk-kWh})
- Winter OffPeak Non-Embedded NO_x Benefit (\$) = kWh * Energy%_{WinterOffPk} * WinterOffPkNonEmbeddedNOxValue\$/kWh_(@Life) * (1 + %Losses_{WinterOffPk-kWh})

- Natural Gas Non-Embedded NOx Benefit (\$) = MMBtu Gas Savings *
GasNonEmbeddedNOxValue\$(Sector)/MMBtu(Gas, @Life)
- Fuel Oil Non-Embedded NOx Benefits (\$) = MMBtu Fuel Oil Savings *
FuelOilNonEmbeddedNOxValue\$(Sector)/MMBtu(Fuel Oil, @Life)
- Propane Non-Embedded NOx Benefits (\$) = MMBtu Propane Savings *
PropaneNonEmbeddedNOx\$/MMtBu(Propane, @Life)

3.11 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 2021 AESC Study used the following methodology to determine the value of improved reliability. As with the 2018 AESC Study, the 2021 AESC Study in part relied on 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. New to the 2021 AESC Study, an additional study was incorporated into the calculations of lost load. Cambridge Economic Policy Associates released a study in July 2018 entitled “Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe.” This study assessed the VoLL in each European Union country for residential customers and 13 types of non-residential customers. The 2021 AESC Study examined annual average VoLLs of EU countries and identified those most similar to the New England region on a GDP per capita basis. To develop the estimate of the VoLL in the AESC report, Synapse averaged findings from the LBNL and Cambridge Economic Policy Associates studies together for each category of customer. Then, using share-of-sales data for the residential, small C&I, and large C&I customer segments, Synapse calculated a weighted average VoLL of \$73 per kWh.

The 2021 AESC Study then examined the ability of load reduction 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 reliability in the following ways:

- Some resources that do not clear ISO New England’s Forward Capacity Auction (FCA) will continue to operate as energy-only resources – adding to available reserves. While not obligated to do so, these resources are likely to operate at times of tight supply and high energy prices. These resources may also be available to assume the capacity obligations of resources that unexpectedly retire or otherwise become unavailable.

- Not all energy efficiency load reductions will clear in the capacity market or immediately affect the load forecast used to determine the amount of capacity acquired. Those load reductions will increase reserve margins.
- The operation of the ISO New England capacity market increases the amount of capacity acquired as the price falls. To the extent that energy efficiency programs reduce the capacity clearing price, reserve margins and reliability will increase.

The 2021 AESC Study monetized cleared reliability benefits in \$/kW-month by calculating the product of (a) the change in MWh of reliability benefits per megawatt of reserve, (b) the net increase in cleared supply, (c) the decay effect, and (d) the VoLL.¹⁶ Uncleared reliability benefit in \$/kW-month is calculated as the product of (a) the change in MWh of reliability benefits per megawatt of reserve, (b) one plus the reserve margin, (c) the load forecast effect, (c) the decay effect, and (e) the VoLL.

As recommended by the 2021 and 2018 AESC Studies, the Company applies different reliability values to measures that clear and don't clear the Forward Capacity Market auction. This is because 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 the 2021 AESC Study to all summer kW savings associated with cleared measures and the Reliability Value of Uncleared EE (\$/kW-year) from the 2021 AESC Study to all summer kW savings associated with uncleared measures. Reliability values are sourced from the AESC User Interface file Appendix B, Counterfactual #4.

The reliability benefit is calculated as follows with the reliability value in \$/kW changing whether a measure is assumed to be cleared or uncleared in the FCM auction. The 2021 AESC Study Counterfactual #4 finds that the 15-year levelized benefit of increasing generation reserves through reduced energy usage is \$0.49/kW-year for cleared resources.

- Wholesale Reliability Value Benefit (\$) = $kW_{Summer} * ReliabilityValue_{\$/kW_{(Life)}} * (1 + \%Losses_{SummerkW})$

3.12 Combined Heat and Power 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)

¹⁶ Refer to the 2021 AESC Study section 11.2 for additional detail on the derivation of each of these components.

energy supply costs; (iv) greenhouse gas emissions standards and air quality benefits; and (v) system reliability benefits.¹⁷ Energy and cost savings and energy supply costs are captured in the energy benefits described above. The other three listed benefits – economic development, greenhouse gas, and system reliability benefits – are described below and will be applied to eligible CHP projects, should any be proposed.

Economic Development

As provide by the statute, for all CHP projects, net economic development benefits will be counted as benefits. If the CHP project is smaller than 3 MW, the gross state product multipliers for the program in which it is implemented (e.g., C&I retrofit) presented in Table 1 or Table 2 below will be used to calculate the benefits. The rate of economic development benefit of lifetime gross state product increases per dollar of program investment for CHP projects less than 3 MW is based on the report, “Review of RI Test and Proposed Methodology” prepared for the Company by the Brattle Group, January 31, 2019. The 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 program multiplier.

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.¹⁸ The economic benefits from this analysis are added to the economic benefits for the program derived from all other measures in this program to arrive at the total program benefits.

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 SO_x, NO_x, and CO₂. Similarly, the amount of

¹⁷ See R.I. Gen.Laws § 39-1-27.7(c) (6) (iii).

¹⁸ In the 2024 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, weighted by incentives to be spent on CHP and the rest of C&I Retrofit projects. CHP expenditures, besides incentives, are not disaggregated from the rest of the expenditures for the C&I Retrofit program so the multiplier cannot be applied directly to program spending for CHPs. The final weighted average multiplier applied to the total C&I Retrofit program, including CHP, was \$5.72.

emissions for all pollutants associated with a particular CHP unit is not always provided. Where locational information is not available, the value of CO₂ emission reductions and NO_x 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.¹⁹ 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;²⁰
- 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;
- 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.²¹

¹⁹ 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.

²⁰As explained in footnote 10, *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.

²¹ 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.

3.13 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.
- **Cost of services and product rebates/incentives provided to customers:** These are the incentives (provided by the program) that customers use 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, costs 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.²² 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 expeditors, 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.

²² The full cost of the efficiency project is not necessarily the same as the full cost of the project being undertaken by the customer. For example, a customer may be renovating an HVAC project that includes a newly installed chiller and chilled water distribution system. 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.

- **Performance Incentive:** This is the incentive received by the Company for meeting specified savings goals and/or performance targets (the Company would not implement energy efficiency programs to the extent it does without the incentive). The performance (shareholder) incentive is included in the cost of energy efficiency.

3.14 Customer Costs

Customer costs include the customer's 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.

In addition to the direct costs that customers face to purchase energy efficient equipment, they may have additional costs for participating in energy efficiency programs that are not quantified and monetized. For example, a customer participating in a home energy assessment may need to spend some amount of time at home in order to facilitate the assessment, creating some time cost for the customer to participate. The magnitude and value of these additional potential time costs are currently unknown. They would likely vary by sector, program, and possibly measure and are therefore challenging to estimate reliably.

4 Benefit Cost Calculations

The cost-effectiveness of a measure, program, or portfolio is determined by calculating whether the ratio of the net present value of the benefits to the net present value of the costs is greater than or equal to 1.

For the 2024 Annual Plan, all costs and benefits will be expressed in constant 2024 dollars. When escalation of specific avoided cost inputs is needed to produce values in 2024 dollars, appropriate inflation rates are used.²³

The avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2024 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 future year values are in constant 2024 dollars, calculated lifetime benefits are discounted back to mid-2024 using a real discount rate equal to $[(1 + \text{Nominal Discount Rate}) / (1 + \text{Inflation})] - 1$.

²³ Inflation of avoided costs was made using assumptions from the 2021 AESC Study. The assumed inflation is lower than the recently experienced inflation. However, as noted above, the AESC Study provides a long-term view that is appropriate for energy efficiency planning.

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 Least-Cost Procurement. Energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk.” For the 2024 Annual Plan, the Company modified the approach used to calculate the discount rate. For the 2021 Annual Plan and prior years, the real discount rate was calculated from the twelve-month average of the historic daily real yields from a ten-year United States Treasury note, using the preceding calendar year to determine the twelve-month average. During 2021, Treasury yields exhibited atypical behavior, with several daily yields being less than zero, in part due to the influence of the Covid-19 Pandemic and its prolonged economic impacts. To account for this behavior, three years of past data (2019 – 2021) were used to calculate the discount rate. Additionally, in any case when the daily yield was negative, the value was set to zero for purposes of the averaging calculation. These calculations resulted in a real discount rate of 0.14% and nominal discount rate of 1.49%. If observed real yields only were used for 2021, a negative real discount rate would have resulted.

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 + Non-embedded NOx Reduction Benefits + Value of Improved Reliability + Economic Development Benefits (treatment as described above)]

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 ratio 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.²⁴

On a sector level, the cost of pilots, community-based initiatives, sector financing, workforce development, 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

²⁴ 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.

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 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.

5 Economic Impacts (Non-CHP Measures)²⁵

Per the practice first set for the 2022 Plan and with the agreement of stakeholders, economic impacts are presented separately and not included in the estimation of the RI Test ratios. The Rhode Island PUC may consider the estimated value of these economic impacts in their determination of cost-effectiveness under the Least Cost Procurement standards.²⁶

The macroeconomic multipliers for the economic growth and job creation benefits of investing in cost-effective energy efficiency are based on the report, “Economic Impacts of Rhode Island Energy’s 2023 Annual Energy Efficiency Plan” prepared for the Company by the Brattle Group in 2023. This study is an update to “Review of RI Test and Proposed Methodology” prepared for the Company by the Brattle Group in 2019. The updated study identified values for other categories of economic impact identified by the Division (i.e., business income, personal income, state income taxes) and gave attention to the question of how double counting of economic benefits in cost-effectiveness testing can be avoided. The presentation of economic impacts in Attachments 5 and 6 includes gross domestic product associated with the proposed investment in energy efficiency in Rhode Island in 2024 using values derived from the Brattle study. The macroeconomic multipliers for job-years associated with proposed investments in energy efficiency are still sourced from the Brattle Group’s 2019 report. The Brattle Group’s 2023 report did not contain updated job-year multipliers.

The exclusion of economic benefits from cost-effectiveness calculations was motivated by the DPUC, via their consultant Synapse Energy Economics, who conducted a benefit cost analysis and assessment of the treatment of macroeconomic benefits of the RI Community Remote Net Metering (CRNM) program in

²⁵ This section details the methodology for applying economic benefits to non-CHP measures. Section 13 in this document refers to the application of economic benefits to CHP measures.

²⁶ LCP Standards, Section 3.2(N) states “qualitative benefits and costs may be considered in determining cost-effectiveness.” The exception to this would be for Combined Heat and Power facilities, since the inclusion of economic benefits is required by statute.

early 2021.²⁷ This analysis recommended that, due to the challenges of fully separating all benefit streams within macroeconomic benefits from those already included in other benefit categories counted in the RI Test, the results of an economic impact assessment (EIA) should be shown separately from a BCA and that further discussion of the approach to including economic benefits in the RI Test are warranted to refine the estimation of macroeconomic benefits.

For the 2024 Annual Energy Efficiency Plan, the Company shows RI Test results without economic impacts included. Omission of the macroeconomic benefits and other economic impacts lowers benefit cost ratios for all programs and the portfolios as a whole. Because this is a conservative approach to addressing potential double counting and likely underestimates cost-effectiveness, the Company submits that the cost-effectiveness of its programs and portfolios is likely greater than what is shown for the RI Test and requests that the Commission take this into consideration when assessing the cost-effectiveness of the Plan.

²⁷ <http://www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf>

Figure 1. Multipliers by Energy Efficiency Program Type

Program Type	GDP / \$ Program Spending	Job Years / \$M Program Spending
Electric Portfolio		
<i>Residential Programs</i>		
Residential New Construction	1.66	14.8
Residential HVAC	1.45	12.2
EnergyWise Single Family	1.17	12.3
EnergyWise Multifamily	1.97	14.8
Home Energy Reports	2.17	13.6
Residential Consumer Products	1.76	8.5
Income Eligible Single Family	1.67	10.9
Income Eligible Multifamily	2.37	13.4
<i>C&I Programs</i>		
Large C&I New Construction	4.76	19.0
Large C&I Retrofit	2.06	51.4
Small Business Direct Install	1.97	12.3
Gas Portfolio		
<i>Residential Programs</i>		
Residential New Construction	1.19	2.4
Residential HVAC	1.06	6.9
EnergyWise Single Family	0.87	11.9
EnergyWise Multifamily	2.30	16.5
Home Energy Reports	2.77	7.5
Income Eligible Single Family	1.53	12.1
Income Eligible Multifamily	2.31	16.0
<i>C&I Programs</i>		
Large C&I New Construction	5.28	1.2
Large C&I Retrofit	1.92	16.4
Small Business Direct Install	2.50	13.4
C&I Multifamily	3.46	11.0
Demand Response Portfolio		
C&I ConnectedSolutions	2.99	17.5
Residential ConnectedSolutions	2.25	6.9

6 Docket 4600 Benefit Cost Framework

Table 1. Alignment of RI Test to Docket 4600 Framework for 2024 Electric Energy Efficiency Portfolio

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
Power System Level	1	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Quantified	\$18,863,402	Energy Efficiency Measures: Winter peak electric energy (kWh) savings are monetized for winter peak by multiplying savings during this period by the avoided retail cost of winter peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit
			Quantified	\$16,872,599	Energy Efficiency Measures: Winter off-peak electric energy (kWh) savings are monetized for winter peak by multiplying savings during this period by the avoided retail cost of winter off-peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit
			Quantified	\$9,523,936	Energy Efficiency Measures: Summer peak electric energy (kWh) savings are monetized for winter peak by multiplying savings during this period by the avoided retail cost of Summer peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit
			Quantified	\$6,502,571	Energy Efficiency Measures: Summer off-peak electric energy (kWh) savings are monetized for winter peak by multiplying savings during this period by the avoided retail cost of Summer off-peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit
			Quantified	\$4,677,854	Energy Efficiency Measures: Value of avoided summer generation capacity benefit is monetized by the AESC 2021 study avoided costs	Benefit

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
	2	Renewable Energy Credit Cost / Value	Quantified	See Notes	Wholesale cost of RECs is included in the winter peak, winter off-peak, summer peak, and summer off-peak retail energy costs from the preceding category.	Benefit
	3	Retail Supplier Risk Premium	Quantified	See Notes	Wholesale Risk Premium is built into the retail costs of electric energy and electric capacity sourced from the AESC 2021 study and used to calculate the benefits of avoided energy and capacity.	Benefit
	4	Forward Commitment: Capacity Value	Quantified	See Notes	Forward capacity avoided costs are included in capacity benefits.	Benefit
	5	Forward Commitment: Avoided Ancillary Services Value	Not applicable	See Notes	Not applicable to energy efficiency	Not Applicable
	6	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Quantified	\$96,307,174	Rhode Island Energy costs to implement the electric energy efficiency portfolio. Total budget includes costs for Program Planning & Administration; Marketing; Customer Incentives; Sales Technical Assistance and Training; Evaluation & Market Research; Performance Incentive Mechanism	Cost
	7	Electric PTF Transmission Capacity Costs / Value	Quantified	\$8,937,231	Energy Efficiency: Electric transmission capacity benefits are quantified by multiplying a statewide Pooled Transmission Facility (PTF) transmission value from AESC 2021 study by the summer kW saved from efficiency measures	Benefit
		Electric Non-PTF Transmission Capacity Costs / Value	Quantified	\$1,060,916	Energy Efficiency: Electric transmission capacity benefits are quantified by multiplying a statewide Pooled Transmission Facility (PTF) transmission value from AESC 2021 study by the summer kW saved from efficiency measures	Benefit
	8	Electric transmission infrastructure costs for Site Specific Resources	Not applicable	See Notes	Currently no location-specific energy efficiency included, all measures offered across service territory.	Not Applicable

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
	9	Net risk benefits to utility system operations (generation, transmission, distribution)	Not Quantified or Qualified	See Notes	Value of Improved Reliability benefit calculated based on reliability value from the AESC 2021 study multiplied by the avoided summer kW savings. Values included in the row "Distribution system and customer reliability / resilience impacts"	Benefit
	10	Option value of individual resources	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	11	Investment under Uncertainty: Real Options Cost / Value	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	12	Energy Demand Reduction Induced Price Effect	Quantified	\$1,503,846	Energy Efficiency measures: Electric Energy (kWh) Intrastate DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit
Quantified			\$18,122,035	Energy Efficiency measures: Electric Energy (kWh) Rest-of-Pool DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit	
Quantified			\$194,776	Energy Efficiency measures: Electric Energy (kWh) Cross-DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit	
Quantified			\$6,933,409	Energy Efficiency measures: Electric Generation Capacity (kW) DRIPE value quantified by multiplying avoided summer kW by applicable capacity DRIPE values (\$/kW) from the AESC 2021 study.	Benefit	

Schedule B

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
			Quantified	See Fuel benefits	Additional DRIPE benefits for oil fuel savings from energy efficiency measures are quantified by multiplying oil fuel savings (MMBtu) by applicable oil DRIPE values (\$/MMBtu) from the AESC 2021 study. These benefits are included in the category "Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water".	Benefit
			Quantified	See notes	Gas Resource Benefits in the Electric energy efficiency Benefit Cost Model includes Gas Supply DRIPE and Gas-Electric Cross DRIPE monetized by multiplying the gas savings attributable to the electric portfolio measures by applicable avoided cost series from the AESC 2021 study. These benefits are included in the category "Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water".	Benefit
	13	Greenhouse gas compliance costs	Quantified	See notes	Cost of compliance with criteria air pollutant regulations are included in the wholesale electric energy commodity costs from the AESC 2021 study and are included in the calculation of the energy benefits in the category "Energy Supply & Transmission Operating Value of Energy Provided or Saved"	Benefit
	14	Criteria air pollutant and other environmental compliance costs	Quantified	See notes	Cost of compliance with criteria air pollutant regulations are included in the wholesale electric energy commodity costs from the AESC 2021 study and are included in the calculation of the energy benefits in the category "Energy Supply & Transmission Operating Value of Energy Provided or Saved"	Benefit

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
	15	Innovation and Learning by Doing	Not Quantified or Qualified	See notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs. Likely a minimal value in comparison to other benefits included in RI Test, but possible value due to pilots, demonstrations, and assessments included in programs.	Benefit
	16	Distribution capacity costs	Quantified	\$15,564,462	Energy Efficiency: Electric distribution capacity benefits are quantified by multiplying a Company-generated distribution value (\$/kW) by the summer kW saved from efficiency measures.	Benefit
	17	Distribution delivery costs	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	18	Distribution system safety loss/gain	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	19	Distribution system performance	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	20	Utility low income	Quantified	See Notes	Reduced arrearages; bad debt write-offs; terminations and reconnections; notices; safety related emergency calls; customer calls and collections; and rate discounts are included as NEIs for income eligible programs. Aggregated with other NEIs in row "Program participant / prosumer benefits / costs"	Benefit
	21	Distribution system and customer reliability / resilience impacts	Quantified	\$139,395	Energy Efficiency: Value of Improved Reliability benefit calculated based on reliability value from the AESC 2021 study multiplied by the avoided summer kW savings.	Benefit
Customer Level	22	Program participant / prosumer benefits / costs	Quantified	\$17,495,754	Energy Efficiency measures: Participant contribution cost is the direct cost of the measure that is not covered by the customer	Cost

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
					rebate/incentive for energy efficiency measures.	
			Quantified	\$30,954,031	Quantifiable non-resource, non-energy impacts are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan. Non resource, 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. Includes quantified utility NEIs noted elsewhere in this table, and national security NEI value.	Benefit
	23	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Quantified	\$22,318,538	Energy Efficiency measures: Quantification of Resource Benefits from: Natural Gas, Oil, Propane, Water & Sewage. Natural Gas Benefits are based on Appendix C of the 2021 AESC study, Oil and Propane Benefits are based on Appendix D of the 2021 AESC study, Water & Sewage Benefits are derived from an internet survey of rates posted to the RI PUC website.	Benefit
	24	Low-Income Participant Benefits	Quantified	See Notes	Low-Income Participant Benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan and TRM. See the category "Program participant / prosumer benefits / costs" for these benefits	Benefit
	25	Consumer Empowerment & Choice	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
	26	Non-participant (equity) rate and bill impacts	Quantified	See Notes	External to cost effectiveness analysis. Bill Impacts model the effects of efficiency programs on annual customer bills by aggregating rate and consumption changes, including non-participants. Electric and natural gas rate and bill impact models included in Attachment 7 of the Annual Plan	Benefit (but not included in BCA screening)
Societal Level	27	Greenhouse gas externality costs	Quantified	\$30,035,690	Energy Efficiency measures: Quantified Non-embedded Greenhouse gas reduction benefits obtained from the 2021 AESC Study. Non-embedded CO2 values are sourced from the following tables in the 2021 AESC Study Appendix B for electric savings and Appendix G for gas savings, oil savings, and propane savings.	Benefit
	28	Criteria air pollutant and other environmental externality costs	Quantified	\$1,082,192	Energy Efficiency measures: Quantified Non-embedded NOx reduction benefits obtained from the 2021 AESC Study. Additional research would be required to determine other benefit streams from air pollutants and other environmental externalities	Benefit
	29	Conservation and community benefits	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined
	30	Non-energy costs/benefits: Economic Development	Quantified	\$212,046,709	Energy efficiency measures: The Company is treating the economic benefits category qualitatively in the primary RI Test and are presented separately in an additional table. Economic benefits are calculated by multiplying program spending by a set of multipliers calculated in accordance with a methodology developed in the report: "Brattle Group Review of RI Test and Proposed Methodology Final"	Benefit

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost
	31	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Qualified	Likely minimal value	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs. The portfolio of programs includes pilots, demonstrations and assessments and these likely generate benefits to further program and market development. The value of these innovation and knowledge spillover benefits is unknown but is estimated to be small in comparison to the overall magnitude of benefits currently included in the screening of the electric portfolio.	Benefit
	32	Societal Low-Income Impacts	Not Quantified or Qualified	See Notes	Participant Low-Income Benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan and TRM. Societal low-income impacts are not included. Participant NEIs are aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Undetermined
	33	Public Health	Not Quantified or Qualified	See Notes	Participant health benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan, societal public health benefits are not monetized. Participant NEIs are aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Benefit
	34	National Security and US international influence	Quantified	See Notes	National Security due to avoided oil imports are monetized for residential and income eligible measures that save oil in accordance with the Rhode Island TRM. The value of this NEI is aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Benefit

Table 2. Alignment of RI Test to Docket 4600 Framework for 2023 Natural Gas Energy Efficiency Portfolio

Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
Power System Level	1	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Quantified	\$28,377,765	Natural gas energy efficiency measures. Value of natural gas supply monetized by the AESC 2021 study avoided costs. Natural Gas Benefits are based on Appendix C of the 2018 AESC study. Includes avoided cost of delivering gas (retail margin) and the avoided cost of the gas.	Benefit	Yes
			Quantified	\$77,235	Energy Efficiency Measures: Winter peak electric energy (kWh) savings associated with natural gas efficiency are monetized for winter peak by multiplying savings during this period by the avoided retail cost of winter peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit	No
			Quantified	\$88,935	Energy Efficiency Measures: Winter off-peak electric energy (kWh) savings associated with natural gas efficiency are monetized for winter peak by multiplying savings during this period by the avoided retail cost of winter off-peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit	No
			Quantified	\$91,891	Energy Efficiency Measures: Summer peak electric energy (kWh) savings associated with natural gas efficiency are monetized for winter peak by multiplying savings during this period by the avoided retail cost of Summer peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit	No
			Quantified	\$79,478	Energy Efficiency Measures: Summer off-peak electric energy (kWh) savings associated with natural gas efficiency are monetized for winter peak by multiplying savings during this period by the avoided retail cost of Summer off-peak energy from Appendix B of the avoided cost schedules in the AESC 2021 study.	Benefit	No
			Quantified	\$124,249	Energy Efficiency Measures: Value of avoided summer generation capacity benefit is monetized by the AESC 2021 study avoided costs.	Benefit	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	2	Renewable Energy Credit Cost / Value	Quantified	See Notes	Wholesale cost of RECs is included in the winter peak, winter off-peak, summer peak, and summer off-peak retail energy costs from the preceding category.	Benefit	No
	3	Retail Supplier Risk Premium	Quantified	See Notes	Wholesale Risk Premium is built into the retail costs of electric energy and electric capacity sourced from the AESC 2021 study and used to calculate the benefits of avoided energy and capacity.	Benefit	No
	4	Forward Commitment: Capacity Value	Quantified	See Notes	Forward capacity avoided costs are included in capacity benefits.	Benefit	No
	5	Forward Commitment: Avoided Ancillary Services Value	Not applicable	See Notes	Not applicable to energy efficiency	Not Applicable	No
	6	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Quantified	\$33,255,011	Rhode Island Energy costs to implement the natural gas energy efficiency portfolio. Total budget includes costs for Program Planning & Administration; Marketing; Customer Incentives; Sales Technical Assistance and Training; Evaluation & Market Research; Performance Incentive Mechanism.	Cost	Yes
	7	PTF Electric Transmission Capacity Costs / Value	Quantified	\$229,230	Energy Efficiency: Electric transmission capacity benefits are quantified by multiplying a Pooled Transmission Facility (PTF) transmission value from AESC 2021 study by the summer kW saved from efficiency measures.	Benefit	No
		Non-PTF Electric Transmission Capacity Costs / Value	Quantified	\$19,012	Energy Efficiency: Electric transmission capacity benefits are quantified by multiplying a Non-Pooled Transmission Facility (Non-PTF) transmission value from AESC 2021 study by the summer kW saved from efficiency measures.	Benefit	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	8	Electric transmission infrastructure costs for Site Specific Resources	Not applicable	See Notes	Currently no location-specific energy efficiency included, all measures offered across service territory.	Not Applicable	No
	9	Net risk benefits to utility system operations (generation, transmission, distribution)	Quantified	See Notes	Value of Improved Reliability benefit calculated based on reliability value from the AESC 2021 study multiplied by the avoided summer kW savings. Values included in the row "Distribution system and customer reliability / resilience impacts".	Benefit	No
	10	Option value of individual resources	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined	Undetermined
	11	Investment under Uncertainty: Real Options Cost / Value	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined	Undetermined
	12	Energy Demand Reduction Induced Price Effect	Quantified	\$5,286	Energy Efficiency measures: Electric Energy (kWh) Intrastate DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit	No
Quantified			\$63,123	Energy Efficiency measures: Electric Energy (kWh) Rest-of-Pool DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit	No	
Quantified			\$891	Energy Efficiency measures: Electric Energy (kWh) Cross-DRIPE values quantified based on the energy DRIPE values included in the AESC 2021 study. Calculated for each of winter peak, winter off-peak, summer peak, and summer off-peak.	Benefit	No	
Quantified			\$82,477	Energy Efficiency measures: Electric Generation Capacity (kW) DRIPE value quantified by multiplying avoided summer kW by applicable capacity DRIPE values (\$/kW) from the AESC 2021 study.	Benefit	No	

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
			Quantified	See Fuel benefits	Additional DRIPE benefits for oil fuel savings from energy efficiency measures are quantified by multiplying oil fuel savings (MMBtu) by applicable oil DRIPE values (\$/MMBtu) from the AESC 2021 study. These benefits are included in the category "Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water". Natural Gas measures do not have delivered fuel savings, so no value for the natural gas portfolio.	Benefit	No
			Quantified	\$226,265	Gas Supply DRIPE monetized by multiplying the gas savings attributable to the electric portfolio measures by applicable avoided cost series from the AESC 2021 study. These benefits are included in the category "Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water".	Benefit	Yes
	13	Greenhouse gas compliance costs	Quantified	See notes	Cost of compliance with criteria air pollutant regulations are included in the wholesale electric energy commodity costs from the AESC 2021 study and are included in the calculation of the electric energy benefits in the category "Energy Supply & Transmission Operating Value of Energy Provided or Saved"	Benefit	No
	14	Criteria air pollutant and other environmental compliance costs	Quantified	See notes	Cost of compliance with criteria air pollutant regulations are included in the wholesale electric energy commodity costs from the AESC 2021 study and are included in the calculation of the electric energy benefits in the category "Energy Supply & Transmission Operating Value of Energy Provided or Saved"	Benefit	No
	15	Innovation and Learning by Doing	Qualified	Likely minimal value	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs. Likely a minimal value in comparison to other benefits included in RI Test, but possible value due to pilots, demonstrations, and assessments included in programs.	Undetermined	Undetermined
	16	Distribution capacity costs	Quantified	\$282,031	Energy Efficiency: Electric distribution capacity benefits are quantified by multiplying a Company-generated distribution value (\$/kW) by the summer kW saved from efficiency measures.	Benefit	Undetermined
	17	Distribution delivery costs	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of natural gas energy efficiency programs.	Undetermined	Undetermined
	18	Distribution system safety loss/gain	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of natural gas energy efficiency programs.	Undetermined	Undetermined

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	19	Distribution system performance	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of natural gas energy efficiency programs.	Undetermined	Undetermined
	20	Utility low income	Quantified	See Notes	Reduced arrearages; bad debt write-offs; terminations and reconnections; notices; safety related emergency calls; customer calls and collections; and rate discounts are included as NEIs for income eligible programs. Aggregated with other NEIs in row "Program participant / prosumer benefits / costs"	Benefit	No
	21	Distribution system and customer reliability / resilience impacts	Quantified	\$1,010	Value of Improved Reliability benefit calculated based on reliability value from the AESC 2021 study multiplied by the avoided summer kW savings. Applies to energy efficiency measures.	Benefit	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
Customer Level	22	Program participant / prosumer benefits / costs	Quantified	\$6,854,409	Energy Efficiency measures: Participant contribution cost is the direct cost of the measure that is not covered by the customer rebate/incentive for energy efficiency measures.	Cost	No
			Quantified	\$27,818,033	Quantifiable non-resource, non-energy impacts are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan. Non resource, 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. Includes quantified utility NEIs noted elsewhere in this table, and national security NEI value.	Benefit	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	23	Participant non-energy costs/benefits: Oil, Water, Waste Water	Quantified	\$512,053	Energy Efficiency measures: Quantification of Resource Benefits from: Oil, Propane, Water & Sewage. Oil and Propane Benefits are based on Appendix D of the 2021 AESC study, Water & Sewage Benefits are derived from an internet survey of rates posted to the RI PUC website.	Benefit	No
	24	Low-Income Participant Benefits	Quantified	See Notes	Low-Income Participant Benefits benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan. See the category "Program participant / prosumer benefits / costs" for these benefits	Benefit	No
	25	Consumer Empowerment & Choice	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs.	Undetermined	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	26	Non-participant (equity) rate and bill impacts	Quantified	See Notes	External to cost effectiveness analysis. Bill Impacts model the effects of efficiency programs on annual customer bills by aggregating rate and consumption changes, including non-participants. Electric and natural gas rate and bill impact models included in Attachment 7 of the Annual Plan	Benefit (but not included in BCA screening)	No
Societal Level	27	Greenhouse gas externality costs	Quantified	\$19,820,251	Energy Efficiency measures: Quantified Non-embedded Greenhouse gas reduction benefits obtained from the 2021 AESC Study. Non-embedded CO2 values are sourced from the following tables in the 2021 AESC Study Appendix B for electric savings and Appendix G for gas savings, oil savings, and propane savings.	Benefit	No
	28	Criteria air pollutant and other environmental externality costs	Quantified	\$2,389,919	Quantified Non-embedded NOx reduction benefits obtained from the 2021 AESC Study. Additional research would be required to determine other benefit streams from air pollutants and other environmental externalities	Benefit	No
	29	Conservation and community benefits	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of natural gas energy efficiency programs.	Undetermined	Undetermined

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	30	Non-energy costs/benefits: Economic Development	Qualified	\$66,899,831	Energy efficiency measures: The Company is treating the economic benefits category qualitatively in the primary RI Test and presenting economic benefits in a separate table. Economic benefits are calculated by multiplying program spending by a set of multipliers calculated in accordance with a methodology developed in the report: "Brattle Group Review of RI Test and Proposed Methodology Final"	Benefit	No

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	31	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Qualified	Likely minimal value	Additional research necessary to determine applicability and qualitative/quantitative impacts for cost effectiveness screening of energy efficiency programs. The portfolio of programs includes pilots, demonstrations and assessments and these likely generate benefits to further program and market development. The value of these innovation and knowledge spillover benefits is unknown but is estimated to be small in comparison to the overall magnitude of benefits currently included in the screening of the electric portfolio.	Benefit	Undetermined
	32	Societal Low-Income Impacts	Not Quantified or Qualified	See Notes	Participant Low-Income Benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan and TRM. Societal low-income impacts are not included. Participant NEIs are aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Undetermined	Undetermined

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Category Level	Cat. #	Mixed Benefit-Cost, Cost, or Benefit Category	Treatment in Benefit-Cost Analysis (Quantified, Qualified, Not Treated)	Present Value or Qualitative Description	Description and Notes	Benefit or Cost	Related to Gas Utility Service (Yes/No)
	33	Public Health	Quantified	See Notes	Participant health benefits are included within the calculation of Non-Energy Impacts as described within the Non-Energy Impacts section of the Annual Plan, societal public health benefits are not monetized. Participant NEIs are aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Benefit	No
	34	National Security and US international influence	Quantified	See Notes	National Security due to avoided oil imports are monetized for residential and income eligible measures that save oil in accordance with the Rhode Island TRM. The value of this NEI is aggregated with other Non-Energy Impacts and shown in the Program participant / prosumer benefits / costs category.	Benefit	Undetermined