2022 Rhode Island Test Description

Table of Contents

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 Order No. 23890 in Docket No. 5015[1] (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 for the calculation of benefits and costs associated with the 2022 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 2022 Rhode Island Technical Reference Manual, which documents the savings or savings algorithms and costs for measures proposed to be offered through its programs in 2022. The TRM identifies the sources for the savings estimates. Sources can be evaluation studies, engineering analyses, and/or other research or analysis. This TRM is a public document and was provided to the EERMC and its consultants to support and facilitate the 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) sponsored by the New England electric and gas efficiency program administrators to be used for cost effectiveness screening in 2021 or later. The avoided costs reflect current and expected market conditions 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. There were several noted changes to the avoided costs in the 2021 AESC Study compared to the 2018 iteration of the AESC study.

The 2021 AESC Study introduced four counterfactual scenarios representing variations in demand-side measures offered in the future. For cost-effectiveness screening of the 2022 Rhode Island energy efficiency portfolio the Company used Counterfactual #4 as the best representative scenario for the DSM portfolios in the near future. Counterfactual models a future in which program administrators install no new energy efficiency resources in 2021 or later years. This future does model some amount

[1] RI PUC Docket 5015, Least Cost Procurement Standards
http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf

of building electrification installed by the program administrators but does not include any active demand management resources installed by the program administrators.[2]

Summarizing from the Executive Summary of the 2021 AESC Study, key differences between the AESC 2018 and AESC 2021 studies are:

- Generally lower avoided costs of energy, due to sustained low natural gas prices at national hubs, lower estimated costs of complying with the Regional Greenhouse Gas Initiative (RGGI), and increased quantities of zero-marginal-cost renewables.
- Generally lower avoided costs of capacity due to a relatively flat supply curve based on observations of recent forward capacity auctions.
- Generally lower avoided costs of natural gas, based on lower long-term projections of wholesale natural gas prices. Avoided natural gas costs for retail end-users are also lower than in AESC 2018; but because incremental gas pipeline expansion costs are assumed to be higher, the change in avoided costs at the end-user level is not as large as the reduction in gas commodity prices.
- Generally higher avoided costs for fuel oil and other fuels, due to updates to recent historical data in the underlying sources used to calculate these values.
- Generally higher avoided costs for renewable portfolio standard (RPS) compliance. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification.
- Lower energy DRIPE and capacity DRIPE values, due to changes in utility long-term energy purchases, updated market data, and new commodity forecasts. Natural gas DRIPE and oil DRIPE values are also lower due to similar changes.
- Both higher and lower non-embedded costs for environmental regulations that are not otherwise included in the above projections (e.g., carbon dioxide, and nitrogen oxides) depending on the approach used to calculate this number. AESC 2021 presents a number of different non-embedded costs for use in different state policy contexts.
- Lower avoided costs for pooled transmission facility (PTF) costs, as a result of a switch to a forward-looking methodology (AESC 2018 utilized a historical methodology).
- Generally lower avoided costs for reliability, due to a flatter supply capacity market supply curve. This is in spite of a higher estimate for value of lost load (VoLL), determined through newly available data sources."

Further quantitative detail is provided in the Executive Summary of the 2021 AESC Study showing differences between the 2018 and 2021 AESC Studies in ES-Tables 1-4.

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

The RI Test captures the value created by efficiency measures installed in a particular program year over the useful life of the measure. The measure life is based on the technical life of the measure modified to reflect expected measure persistence. Because the RI Test captures the value associated with a stream of benefits over a period of time, the benefits from a measure are present valued so that costs and benefits may be compared.

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

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

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

On the other hand, if a customer accepts program funds to implement an energy efficiency measure they would have done anyway, the savings associated with this practice is known as "free-ridership." From the perspective of resource acquisition through utility programs, it is important to distinguish whether the customer would have implemented the efficiency measure without the program. Therefore, savings associated with free-ridership are deducted from program savings.[3]

[3] Both free-ridership and spillover have been determined from evaluation, measurement, and verification studies of program participants, non-participants, and other market actors.

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

3 Description of Program Benefits and Costs

The following benefits and costs are included as quantified and monetized in the RI Test. They are listed here with details after. Section 5 of this document shows the alignment of each of these benefit and cost categories to the Docket 4600 Benefit-Cost Matrix for the electric portfolio.

- 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
- Price Effects (DRIPE)
- Non-embedded Greenhouse Gas Reduction Benefits
- Economic Development Benefits
- Non-embedded NOx Reduction Benefits
- Value of Improved Reliability
- Combined Heat and Power Benefits
- Utility Costs
- Participant Costs

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.[4] They include pool transmission losses incurred from the generator to the point of delivery to the distribution companies, the costs of renewable energy credits borne by generators, and a wholesale risk premium that captures market risk factors typically recovered by generators in their pricing. The avoided energy costs also internalize the expected cost of complying with current or reasonably anticipated future regional or federal greenhouse gas reduction requirements which are borne by generators and passed through in wholesale costs.

The avoided energy costs in the 2018 AESC Study are provided in four different costing periods consistent with ISO-NE definitions. Net energy savings are split up into these periods in the value calculation. The time periods are defined as follows:

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

In the benefits calculation, energy savings are grossed up using factors that represent transmission and distribution losses because a reduction in energy use at the customer means that amount of energy does not have to be generated, plus the extra generation that is needed to cover the losses that occur in the delivery of that energy is not needed. A factor for wholesale risk premium is also added to convert the wholesale rates to retail.

Net energy savings for a program (or measures aggregated within a program) are allocated to each one of these time periods and multiplied by the appropriate avoided energy value.[5] The dollar benefits are then grossed up using the appropriate loss factors representing losses from the ISO delivery point to the end use customer.

---

[4] Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short term fuel costs.

[5] The notation "@Life" in the equation for value for this and other value components is an indication that the avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2022 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.

- Summer Peak Energy Benefit ($) = kWh * $Energy_{SummerPk}$ * $SummerPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Summer OffPeak Energy Benefit ($) = kWh * $Energy\%_{SummerOffPk}$ * $SummerOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SummerOffPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Winter Peak Energy Benefit ($) = kWh * $Energy\%_{WinterPk}$ * $WinterPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinterPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Winter OffPeak Energy Benefit ($) = kWh * $Energy\%_{WinterOffPk}$ * $WinterOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinterOffPk\text{-}kWh}$) * (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 generation facilities or when construction can be deferred because of consumers' investments in energy efficiency, an avoided resource benefit is created. In the New England capacity market, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. The capacity requirement is based on load's contribution to the system peak, which, for ISO-NE, is the summer peak. Therefore, capacity benefits accrue only from summer peak demand reduction; there is currently no winter generation capacity benefit.

Demand savings created through program efforts are valued using the avoided capacity values from the 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 to the point of delivery to the distribution companies. ISO-New England reserve margins are incorporated into the capacity values, since energy efficiency avoids the back-up reserves for that generation as well as the generation itself. A loss factor representing losses from the ISO delivery point to the end-use customer is used as a multiplier, since those losses are not included in the avoided costs. Demand savings are calculated to be coincident with the ISO-NE definition of peak.

The dollar value of benefits are therefore calculated as:

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

In addition to the traditional valuation of electric generation capacity, for which results are provided in Appendix B, the 2021 AESC study continued the methodology introduced in 2018 AESC for valuing the capacity of short duration measures that are not actively bid in the ISO-New England Forward Capacity Market (FCM). The AESC study has always provided avoided electric generation capacity values that are

differentiated based on whether a measure is bid in the FCM (cleared capacity) or is not bid in the FCM and passively reduces system load and, as a result, reduces the ISO-NE load forecast and the resulting amount of capacity that is procured through the FCM (uncleared capacity), with the overall avoided capacity value representing a weighted average of the cleared capacity and uncleared capacity values. Given the three year forward nature of the FCM and the timing of the ISO-NE load forecast, it takes five years from the time of load reduction for uncleared capacity to begin impacting the FCM procurements. As a result, measures with a useful life less than five years (ex. demand response) would not produce any generation capacity benefits in years 1-5 under the traditional capacity modeling methodology.

The 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 useful measure life of the measure. The logic behind this analysis is that the ISO-NE load forecast utilizes multiple years of historical load data and that even a load reduction for only one year will have a lasting impact on the load forecast for a number of years. The deferred capacity valuation methodology for uncleared capacity is used to determine the avoided electric generation capacity value for demand response measures based on the values provided in Appendix J of the 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 as a result of consumers' investments in energy efficiency, an avoided resource benefit is created.

Electric distribution capacity benefits are valued in the RI Test using avoided distribution capacity values calculated in a spreadsheet tool that was developed in 2005 by ICF International, Inc., updated with recommendations from the 2018 AESC Study, and carried forward to the 2021 AESC Study. The tool calculates an annualized value of statewide avoided distribution capacity values from company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and Federal Energy Regulatory Commission (FERC) Form 1 accounting data.

Electric transmission capacity benefits are valued in the RI Test based on the costs of Pool Transmission Facilities (PTF). The 2021 AESC study calculates an avoided cost for PTF of $87/kW-year in 2018 dollars. In the 2021 AESC Study the estimation of the PTF values was revised to include transmission projects anticipated to occur through 2026, rather than the purely historical analysis of PTF investments as used in the 2018 AESC Study. The Company continues to use the PTF values instead of local transmission investments in screening the energy efficiency portfolios. PTF values are sourced from Appendix B.

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

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

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

3.4 Natural Gas Benefits

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

Natural gas benefits in the RI Test are valued using avoided natural gas values from the 2021 AESC Study, Appendix C. These costs include commodity, pipeline transportation cost, and retail distribution margin, or 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. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.
- Commercial and industrial, heating. Averages the monthly values for the months of November through March.
- Residential heating. Averages the monthly values for the months of November through March. As these months have the highest natural gas values, by averaging over a fewer number of months, natural gas savings in this category typically have the highest value.
- Residential water heating/residential non-heating. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.
- All commercial and industrial
- All residential
- All retail end-uses

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

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

3.5 Delivered Fuel Benefits

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

Fuel benefits in the RI Test are valued using avoided fuel values from the 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, and industrial residual fuel oil.

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

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

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 a project in which consumers have invested to save electricity or fuel also affects water consumption—for example, a cooling tower project that reduces makeup water needed—a resource benefit is created. Depending on the project and metering configuration, changes in water consumption may also affect sewerage billings.

Water and sewerage rates were determined from an 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.[6]

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

[6] RI Regulated Water Suppliers – Rates Updated September 3, 2020, http://www.ripuc.ri.gov/utilityinfo/water/residentialgri.html

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 they are applied on an annual or one-time basis based on energy saved. They may be positive or negative. They may be one time benefits or recur annually. These effects will be included when they are a direct result of the measure and when they are quantifiable and avoidable.

The specific values of non-energy impacts used in the 2022 Annual Plan for prescriptive measures are documented in the 2022 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.

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 a period of time, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of electricity. This is observed in the New England market when ISO-New England activates its price response programs. When this price effect is a result of consumers' investments in energy efficiency, it is appropriate to include it in the RI Test.

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

DRIPE values developed for energy efficiency installations in 2022 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. There are also cross fuel effects that apply when natural gas energy efficiency affects the price of electricity due to the fact that residential heating and electric generation compete for natural gas supply in the winter. The resulting scarcity of natural gas for generation may drive up the cost of electricity. Therefore, reduction in natural gas consumption due to energy efficiency may cause a price effect for electricity. (Even though the price effect is in electricity, that DRIPE benefit is converted to $/MMBtu so that it can be attributed to the gas savings that create the effect.) In addition, reducing demand for petroleum and refined products leads to a reduction in oil prices. The DRIPE benefit is calculated as:

- Summer Peak Energy DRIPE Benefit ($) = kWh * $Energy\%_{SumPk}$ * ($SummerPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{SummerPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Summer OffPeak Energy DRIPE Benefit ($) = kWh * $Energy\%_{SumOffPk}$ * ($SumOffPkDRIPE\$/kWh_{(@Life}$ +$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{SummerOffPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Winter Peak Energy DRIPE Benefit ($) = kWh * $Energy\%_{WinterPk}$ * ($WinterPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{WinterPk\text{-}kWh}$) * (1 + Wholesale Risk Premium)
- Winter OffPeak Energy DRIPE Benefit ($) = kWh * $Energy\%_{WinOffPk}$ * ($WinterOffPkDRIPE\$/kWh_{(@Life}$+$ElectricGasDRIPE\$/kWh_{)}$ * (1 + $\%Losses_{WinterOffPk\text{-}kWh}$) * (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)(iii) 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 non-embedded cost of carbon. The four methods for calculating non-embedded cost of carbon are:

- A damage cost approximated by the social cost of carbon (SCC);

- A global marginal abatement cost approach;
- An approach based on New England marginal abatement costs, assuming a cost derived from electric sector technologies, with wind being the marginal abatement technology;
- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors.

Consistent with the approach in the 2020 and 2021 Annual Plans, the Company proposes to apply the New England marginal abatement cost derived from electric sector as the non-embedded cost of carbon. Using the regional marginal abatement cost represents a conservative and reasonable non-embedded carbon price that reflects the likely marginal abatement technology for Rhode Island in achieving its carbon reduction goals, including the recently-enacted Act on Climate carbon emission reduction goal of net zero by 2050.

The 2021 AESC Study found that the marginal abatement cost derived from electric sector technologies was 75% higher than the corresponding value estimated in the 2018 AESC Study, at approximately $125, levelized over a 15-year period. In the 2018 AESC Study, the cost of avoided CO2 was reported to be $68 per short ton in 2018 dollars or $72 per short ton in 2021 dollars. The 2021 AESC Study describes three factors for the increase in this value:

- Access to more cost data specific to U.S. projects in New Jersey, New York, Massachusetts, and Maryland. The previous AESC 2018 report primarily relied upon European prices due to a lack of U.S. data.
- Assumes annual changes in the cost of offshore wind (e.g., costs start relatively high but decline over time). AESC 2018 assumed a single, unchanging cost throughout the study period.
- Projected energy prices are lower in this edition of AESC 2021. This causes the residual cost of offshore wind to be higher, relative to AESC 2018.

The costs of compliance with the Regional Greenhouse Gas Initiative (RGGI) are already included or "embedded" in the projected electric energy market prices. Therefore, the difference between the approximately $125 per short ton societal cost and the RGGI compliance costs already embedded in the projected energy market prices represents the value of carbon emissions not included in the avoided energy costs.

An example of this calculation using the 15-year levelized values of the Non-embedded carbon price and embedded RGGI Compliance Cost is shown below. The resulting $ non-embedded avoided cost is applied as a benefit in the RI Test in that year.

- Societal Cost ($123.85) – Embedded RGGI Compliance Cost ($8.50) = Non-Embedded Cost ($115.35)

The Company obtained the non-embedded CO_2 values from User Interface file Appendix B of the 2021 AESC Study for electric savings and User Interface file Appendix G for gas savings and oil savings.

3.10 Economic Development Benefits (Non-CHP Measures)

In 2022, the Company is modifying the treatment of economic development benefits for the energy efficiency programs to more conservatively estimate the RI Test ratios, given potential uncertainty in the value of economic benefits. In program years 2020 and 2021 the Company included economic benefits in the screening of the energy efficiency programs and portfolios to align with the Docket 4600 Framework. These years utilized an updated methodology, described below. Because economic benefits are a category called out in the Docket 4600 Framework, the Company undertook an effort to improve the method of quantification for this benefit stream during 2018 – 2019, resulting in the methodology applied in the two most recent Plan filings. However, during the 2022 planning process the Company has had conversations with stakeholders, led by the Division of Public Utilities and Carriers, regarding challenges in completely eliminating double counting of benefit streams in the calculation of macroeconomic benefits.

The DPUC, via their consultant Synapse Energy Economics, conducted a benefit cost analysis and assessment of the treatment of macroeconomic benefits of the RI Community Remote Net Metering (CRNM) program in early 2021.[7] 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, that 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.

In response to these comments, for the 2022 Annual Energy Efficiency Plan, the Company shows the primary RI Test results without economic benefits included and a qualitative discussion of the macroeconomic benefits is included. A secondary calculation of the RI Test ratio will show results with economic benefits included. Omission of the macroeconomic benefits lowers benefit cost ratios for all programs and the portfolios as a whole.

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

The macroeconomic multipliers for the economic growth and job creation benefits of investing in cost-effective energy efficiency are derived from a recent study "Review of RI Test and Proposed Methodology"

[7] http://www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf

prepared for National Grid by the Brattle Group, January 31, 2019. The revised multipliers resulting from this study and methodology were first incorporated in the screening of the 2020 portfolio of programs.

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

1. The allocation of spending, benefits, and costs to sectors in REMI based on the breakdowns found in each program spending budget and projected benefits instead of the use of total overall Energy Efficiency Plan values. This provides for a program specific economic impact that more accurately reflects how the implementation of each program impacts the RI economy.
2. Changing the allocation of energy efficiency program spending to sectors in the REMI model from using a generic study to using actual electric and gas program budget data that more accurately reflects where money gets spent in the economy.
3. The exclusion of rebates and incentives for Residential Lighting, Home Energy Reports, HVAC, Residential Products, Residential New Construction (RNC) and Large Commercial New Construction from the REMI analysis.
4. Accounting for the negative impacts that reduced energy consumption has on transmission, distribution, and generation spending in Rhode Island.
5. Avoiding double counting of ratepayer benefits and costs in the RI Test by only counting their indirect and induced economic impacts.

These changes provide for a more accurate accounting of the net-incremental benefits of Rhode Island's energy efficiency programs, however given the discussion earlier in this section a conservative assessment of the RI Test has been applied that omits these macroeconomic multipliers. The revised run of the REMI regional economic model of Rhode Island to estimate these economic impacts yielded the following program-specific multipliers for use in the RI Test.

Program Type	GDP/$ Program Spending
Electric Program	
Residential	
Residential New Construction (RNC)	$1.40
HVAC	$1.42
EnergyWise	$0.93
EnergyWise Multifamily	$1.34
Residential Lighting	$1.59
Residential Products	$1.52
Home Energy Reports	$1.00
Single Family - Income Eligible Services	$0.86
Income Eligible Multifamily	$1.19
Commercial and Industrial	
Large Commercial New Construction	$3.11
Large Commercial Retrofit	$5.80
Small Business Direct Install	$1.97
Total Electric Portfolio	**$2.14**
Gas Program	
Residential	
ENERGY STAR® HVAC	$0.83
EnergyWise	$1.01
EnergyWise Multifamily	$1.63
Home Energy Reports	$1.06
Residential New Construction	$0.22
Single Family - Income Eligible Services	$0.99
Income Eligible Multifamily	$1.55
Commercial and Industrial	
Large Commercial New Construction	$1.42
Large Commercial Retrofit	$2.53
Small Business Direct Install	$1.75
Commercial & Industrial Multifamily	$1.89
Total Gas Portfolio	**$1.26**

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

The Company applied the updated multipliers at the program level as part of the secondary calculation of the RI Test.

3.11 Non-embedded NOx Reduction Benefits

In accordance with Section 1.3(C)(iii) of the Standards and the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of nitrogen oxides (NO_x) emission reductions not already embedded in the avoided cost of energy.

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

The 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 NO_2, 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 and Appendix G in the User Interface file for non-electric measures.

3.12 Value of Improved Reliability

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

The 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 replied 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 the EU countries' annual average VoLL for the countries 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 calculate a weighted average VoLL of $73 per kWh.

The 2021 AESC Study then examined the effect of load reduction's ability to increase reserve margins in the ISO New England (ISO-NE) Forward Capacity Market (FCM) and therefore increase reliability in the wholesale generation market.

Load reductions can improve generation reliability in the following ways:

- Some resources that do not clear the 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. They 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 calculated 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.[8] 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 due to the fact that the reliability effect of cleared energy efficiency load reductions will be partially offset by reduction in the amount of other capacity cleared, while uncleared load reductions will not be subject to such offsets.

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

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 ReliabilityValue$/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 ($) = kWSummer * ReliabilityValue$/kW(@Life) * (1 + %LossesSummerkW)

3.13 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) energy supply costs; (iv) greenhouse gas emissions standards and air quality benefits; and (v) system reliability benefits.[9] Of these, energy and cost savings and energy supply costs are captured in the energy benefits described above. The other three benefits – economic development, greenhouse gas, and system reliability benefits – are described here.

Economic Development

For all CHP projects, net economic development benefits will be counted as benefits. The rate of economic development benefit will be $2.13 of lifetime gross state product increase per dollar of program investment for CHP projects less than 3 MW in size, based on the report, "Review of RI Test and Proposed Methodology" prepared for National Grid by the Brattle Group, January 31, 2019. The $2.13 multiplier reflects the present value of lifetime state gross domestic product (GDP) effects of program and participant spending that creates jobs in construction and other industries as the project is planned, and equipment is purchased and installed. Therefore, the CHP Economic Development benefits will be calculated as:

- Program and participant spending($) x $2.13

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

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.[10]

Greenhouse gas emissions standards and air quality benefits

For all CHP projects, greenhouse gas mitigation and air quality benefits will be counted as benefits to the extent they are not already captured in the BCR screening values and to the extent that usable emissions data is available. The emissions profile of the CHP site facility prior to the installation of the retrofit (most likely a combination of grid supplied generation for electricity and an on-site boiler for thermal needs) will be compared to the emissions post-retrofit (most likely the CHP unit alone). The change in emissions in tons will be multiplied by a value of $/ton for each pollutant and the values will be summed over all pollutants and counted as a benefit in the benefit/cost calculation. This method is contingent on having emissions data for all pollutants. This information is often difficult to come by; for example, ISO-New England annually publishes emissions per kWh for only SOx, NOx, and CO_2. Similarly, the amount of emissions for all pollutants associated with a particular CHP unit is not always provided. Where locational information is not available, the value of CO_2 emission reductions and NOx reductions will be calculated consistent with sections 9 and 11 above.

System Reliability

If a CHP project is proposed in a system reliability target area, the system reliability benefits from deferring a distribution system upgrade would be captured in the System Reliability Procurement report. In the context of CHP located elsewhere in the state, system reliability benefits are the local distribution benefits created by the introduction of the CHP unit in the local area. Notably, CHP projects do not produce the same level of deferred distribution investment savings described in Section (3) above, as traditional energy efficiency.[11] Accordingly, the distribution benefits are modified as follows:

[10] In the 2022 Benefit Cost Model, the Company applied a weighted average economic multiplier to the C&I Retrofit program that accounts for the economic multipliers for C&I Retrofit and CHP. CHP expenditures, besides incentives, are not disaggregated from the rest of the expenditures for the C&I Retrofit program so the multiplier cannot be applied directly to program spending for CHPs. Therefore, the Company created a multiplier applicable to both CHP and C&I Retrofit by taking a weighted average of the two multipliers, weighted by incentives to be spent on CHP and the rest of C&I Retrofit projects. The final weighted average multiplier applied to the total C&I Retrofit program, including CHP, was $5.72.

[11] 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.

- 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;[12]
- 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.[13]

3.14 Utility Costs

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

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

[12] As explained in footnote 11, *supra*, while multiple small CHP units may produce some level of savings, these units are still not likely to produce distribution benefits in the same manner as traditional energy efficiency. Therefore, the 0.75 factor is adopted as a planning assumption to represent the contingency that, when a single CHP unit on a feeder fails to perform, the load reappears on the system. As more CHP units, particularly smaller units, are deployed in the state, the diversity of operation may allow the adjustment factor to be increased. The Company intends to review this planning assumption based on actual experience for future EE Program Plan filings.

[13] 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.

equipment and installation costs directly associated with the energy efficient equipment being installed.[14] For a retrofit project, the customer incentives cover a portion of the full cost of the efficiency project, as it is assumed that the alternative to the project is no customer action. For a failed equipment replacement/renovation/new construction project, these customer incentives cover a portion of the incremental additional costs associated with moving to a higher efficiency item or practice compared to what the customer would have done otherwise.

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

3.15 Customer Costs

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

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.

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

The magnitude and value of these additional potential time costs are unknown at this time. 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 simply the ratio of the net present value of the benefits to the net present value of the costs.

For the 2022 Annual Plan, all costs and benefits will be expressed in constant 2021 dollars. Where escalation of avoided costs or costs is needed to produce values in 2021 dollars, appropriate inflation rates are used.

The avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2021 dollars) of lifetime avoided costs for each year of the planning horizon from the base year up to the measure life of the equipment. Since all of the future year values are in constant 2021 dollars, lifetime benefits thus calculated are discounted back to mid-2021 using a real discount rate equal to [(1 + Nominal Discount Rate) / (1 + Inflation)] - 1.

As prescribed by the Standards, all values in the Plan and the benefit-cost model are stated in present value terms, "using a discount rate that appropriately reflects the risks of the investment of customer funds in Least-Cost Procurement. Energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk." For the 2022 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 2020 Treasury yields exhibited atypical behavior, in part due to the influence of the Covid-19 Pandemic. To account for this, three years of past data (2018 – 2020) were used to calculate the discount rate and in any case when the daily yield was negative in 2020 the value was set to zero for purposes of the averaging calculation. These calculations resulted in a real discount rate of 0.42%.

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]

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.[15]

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 targets by sector. At a portfolio level, the allocations to the Office of Energy Resources and EERMC are also included in the cost effectiveness calculation.

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

[15] 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.

5 Docket 4600 Benefit Cost Framework

Table 1. Alignment of RI Test to Docket 4600 Framework for 2022 Electric Energy Efficiency and Active Demand Response 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	$23,847,614	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
				$-	Active Demand Response Measures: The Active Demand Response program (ConnectedSolutions) only operates during the Summer at system peak times, therefore there are no winter energy benefits.	No Value
			Quantified	$21,590,119	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
				$-	Active Demand Response Measures: The Active Demand Response program (ConnectedSolutions) only operates during the Summer at system peak times, therefore there are no winter energy benefits.	No Value
			Quantified	$12,719,630	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
				$1,824	Active Demand Response 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.	
			Quantified	$9,708,392	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

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
				$1,628	Active Demand Response 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.	
			Quantified	$7,064,608	Energy Efficiency Measures: Value of avoided summer generation capacity benefit is monetized by the AESC 2021 study avoided costs	Benefit
				$872,927	Active Demand Response Measures: Value of avoided summer generation capacity benefit is monetized by the AESC 2021 study avoided costs	Benefit
	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 2018 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	$117,072,453	National Grid costs to implement the energy efficiency portfolio (including active demand response measures). Total budget includes costs for Program Planning & Administration; Marketing; Customer Incentives; Sales Technical Assistance and Training; and Evaluation & Market Research	Cost
	7	Electric Transmission Capacity Costs / Value	Quantified	$14,648,067	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
				$3,912,135	Active Demand Response: 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 active Demand Response measures	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
			Quantified	$12,828,708	Energy Efficiency: Electric distribution capacity benefits are quantified by multiplying a Company-generated distribution value ($/kW) by the summer kW saved from efficiency measures.	Benefit
				$3,426,230	Active Demand Response: Electric distribution capacity benefits are quantified by multiplying a Company-generated distribution value ($/kW) by the summer kW saved from active Demand Response 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
	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 2018 study multiplied by the avoided summer kW savings. Applies to both energy efficiency measures and active demand response measures. 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	$25,744,613	Energy Efficiency measures: Electric Energy (kWh) 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
				$248	Demand Response measures: Electric Energy (kWh) 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	$10,130,796	Energy Efficiency measures: Electric Generation Capacity (kW) DRIPE value quantified by multiplying avoided summer kW by applicable capacity DRIPE values ($/kW) from the AESC 2021 study.	Benefit

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
				$3,583,702	Demand Response measures; Electric Generation Capacity (kW) DRIPE value quantified by multiplying avoided summer kW by applicable capacity DRIPE values ($/kW) from the AESC 2021 study.	Benefit
			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". Active demand response measures do not have oil fuel savings and therefore do not have oil DRIPE benefits.	
			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". Active demand response measures do not have gas savings and therefore do not have gas DRIPE benefits.	
	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"	
	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"	
	15	Innovation and Learning by Doing	Not Quantified or Qualified	See notes	Additional research necessary to determine applicabililty 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	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicabililty 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
	17	Distribution delivery costs	Not Quantified or Qualified	See Notes	Additional research necessary to determine applicabililty 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 applicabililty 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 applicabililty 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	$127,727	Value of Improved Reliability benefit calculated based on reliability value from the AESC 2021 study multiplied by the avoided summer kW savings. Applies to both energy efficiency measures and active demand response measures.	Benefit
				$1,147,374		Benefit
Customer Level	22	Program participant / prosumer benefits / costs	Quantified	$18,841,854	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
				$-	Active demand response measures: There is no customer cost for the ConnectedSolutions Active Demand Response program.	Cost
			Quantified	$25,734,458	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 2022 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	$8,076,835	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

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
				$-	Active demand response measures: no corresponding benefits for oil, gas, water, wastewater in the Active Demand Response benefit cost analysis so this value is zero	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 2022 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
	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 2022 Annual Plan	Benefit (but not included in BCA screening)
Societal Level	27	Greenhouse gas externality costs	Quantified	$44,975,107	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 and oil savings.	Benefit
				$4,545	Active Demand Response 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 and oil savings.	Benefit
	28	Criteria air pollutant and other environmental externality costs	Quantified	$536,566	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

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
	30	Non-energy costs/benefits: Economic Development	Qualified	Positive, Magnitude of Millions of Dollars	Energy efficiency measures: Economic activity generated by the programs creates significant benefits for the Rhode Island economy. The latest study incorporated in the 2020 Annual Report indicated that the 2020 programs supported 827 FTEs and 1,093 companies worked with the programs. In 2022 the Company is treating the economic benefits category qualitatively in recognition of possible uncertainty in the calculation methodology used in the 2020 and 2021 Annual Plans.	Benefit
				Positive, Magnitude of Hundreds of Thousand Dollars to Millions of Dollars	Active demand response measures: Economic activity generated by the programs creates significant benefits for the Rhode Island economy. The latest study incorporated in the 2020 Annual Report indicated that the 2020 programs supported 827 FTEs and 1,093 companies worked with the programs. In 2022 the Company is treating the economic benefits category qualitatively in recognition of possible uncertainty in the calculation methodology used in the 2020 and 2021 Annual Plans.	Benefit
	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 2022 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 2022 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

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
	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 2022 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 2022 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
Power System Level	1	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Quantified	$72,447	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	$84,316	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	$83,158	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	$71,976	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	$107,415	Energy Efficiency Measures: Value of avoided summer generation capacity benefit is monetized by the AESC 2021 study avoided costs	Benefit
			Quantified	$32,270,581	Natural gas energy efficiency measures. Value of natural gas supply monetized by the AESC 2018 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
	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

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
	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	$37,620,814	National Grid 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; and Evaluation & Market Research	Cost
	7	Electric Transmission Capacity Costs / Value	Quantified	$140,375	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
			Quantified	$122,940	Energy Efficiency: Electric distribution capacity benefits are quantified by multiplying a Company-generated distribution value ($/kW) by the summer kW saved from efficiency measures.	Benefit
	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
	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
	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	$65,687	Energy Efficiency measures: Electric Energy (kWh) 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

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	$216,391	Energy Efficiency measures: Electric Generation Capacity (kW) DRIPE value quantified by multiplying avoided summer kW by applicable capacity DRIPE values ($/kW) from the AESC 2021 study.	Benefit
			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
			Quantified	$453,272	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
	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
	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
	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
	16	Distribution capacity 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
	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

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
	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
	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
	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	$10,841	Value of Improved Reliability benefit calculated based on reliability value from the AESC 2018 study multiplied by the avoided summer kW savings. Applies to energy efficiency measures.	Benefit
Customer Level	22	Program participant / prosumer benefits / costs	Quantified	$8,337,594	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
			Quantified	$43,853,636	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 2022 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	$686,462	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 2021 Annual Plan. See the category "Program participant / prosumer benefits / costs" for these benefits	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
	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
	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 2022 Annual Plan	Benefit (but not included in BCA screening)
Societal Level	27	Greenhouse gas externality costs	Quantified	$26,498,144	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 and oil savings.	Benefit
	28	Criteria air pollutant and other environmental externality costs	Quantified	$2,765,102	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 natural gas energy efficiency programs.	Undetermined
	30	Non-energy costs/benefits: Economic Development	Qualified	Positive, Magnitude of Millions of Dollars	Energy efficiency measures: Economic activity generated by the programs creates significant benefits for the Rhode Island economy. The latest study incorporated in the 2020 Annual Report indicated that the 2020 programs supported 827 FTEs and 1,093 companies worked with the programs. In 2022 the Company is treating the economic benefits category qualitatively in recognition of possible uncertainty in the calculation methodology used in the 2020 and 2021 Annual Plans.	Benefit
	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

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
	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 2022 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	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 2022 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 2022 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